BOARD DECISIONS

1970 - 1972

ENERGY RESOURCES CONSERVATION BOARD
603 SIXTH AVENUE S.W. • CALGARY, ALBERTA, CANADA • T2P 0T4

B O A R D   D E C I S I O N S

1970 - 1972

NOTE: As of June 1, 1971 the name of the Oil and Gas Conservation Board was changed to the Energy Resources Conservation Board

ENERGY RESOURCES CONSERVATION BOARD
603 - 6 Avenue S. W. • Calgary, Alberta

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Decision 70-1
Application No. 4765

APPROVAL NO. 1153
WAINWRIGHT WAINWRIGHT POOL

THE APPLICATION AND HEARING

Bailey Selburn Oil & Gas Ltd., operator of Wainwright Project No. 4, applied to the Board for amendment of clauses 2 and 5, subclause (1), of Approval No. 1153. The requested amendments would

(1) defer the date requiring the repressuring to 400 pounds per square inch gauge (psig) or shutting-in of producing wells in Project No. 4 from December 31, 1969, to September 30, 1970, and

(2) allow the well located in the North-east part of Legal Subdivision 15 of Section 35, Township 45, Range 6, West of the 4th Meridian, to be converted to water injection.

The application was heard on November 26, 1969 by the Board, with Mr. V. Millard and Mr. D. R. Craig, P. Eng., sitting.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Bailey Selburn Oil & Gas Ltd.	J. Pawelek, P.Eng. G. C. Whittaker, P.Eng.	Baysel
Piute Petroleums Limited	J. M. Fulton, P.Eng. (of Fulton Engineering Limited)	Piute
Board Staff	D. N. Blades, P.Eng. T. R. Barrows, E.I.T.	

BACKGROUND

On December 18, 1968 Proceeding Number 4325 was initiated by the Board because it appeared to it that Baysel

had failed to comply with the provisions of clause 4 of Approval No. 821 and it also appeared that the operator may have failed to comply with the provisions of section 915 of the Oil and Gas Conservation Regulations. Subsequent to the hearing, Decision No. 69-5 was issued. In this Decision the Board concluded that a serious pressure sink had been created in Project No. 4 and this had caused undesirable migration from Project No. 3, gas intrusion into the oil zone and a relatively minor but significant loss of oil. As a result of these conclusions Approval No. 1153 was issued by the Board to supersede Approval No. 821. Clause 5 of Approval No. 1153, in part, reads:

> (1) The pressure in the oil zone at each producing well shall be restored, by water injection or shutting-in of producing wells, to a minimum of 400 pounds per square inch gauge before December 31, 1969, or such other date as may be stipulated upon application.
>
> (2) Well patterns 2, 4 and 8, as designated on Figure 10 of the submission of the Operator dated December 4, 1968, relative to Proceeding No. 4325, shall be operated so that net voidage does not occur on a quarterly basis for a period of eighteen months, commencing April 1, 1969.
>
> (3) The injection rates in the injection wells numbered 11D-36 and 4B-1 shall be maintained, having regard for the resultant effects, at a high level to the satisfaction of the Board until the Board is satisfied that over-injection is no longer required.

SUBMISSION OF THE APPLICANT

Baysel submitted that it had advised the Board by letter dated March 27, 1969, of its concern regarding the feasibility of attaining the 400 psig pressure requirement and at that time it agreed to conduct quarterly rather than semi-annual pressure surveys in Project No. 4. The first two surveys carried out on a quarterly basis and conducted in March and June, 1969, resulted in net pay weighted average pressures in the project of 359 psig and 354 psig respectively. Baysel explained that the large difference between the results of these two surveys and the May, 1968 survey, which resulted in an average pressure for the project of 521 psi, was largely due to a change in the method of estimating the pressure at each water injection well in the project.

Baysel pointed out that only four surveyed producing wells in Project No. 4 indicated pressures in excess of 400 psig as of June, 1969, and that these wells, and the remaining wells in the project, were exhibiting a generally declining pressure although excellent flood response to water injection was indicated. Pressure decline has been observed up to June, 1969, in patterns 2, 4 and 8 where over-injection has been taking place. It was noted that although the September, 1969, survey indicated an increase in pressure in patterns 2, 4 and 8, a general increasing pressure trend could not be assumed due to the unreliability of sonic pressure measurements. Baysel stated that the pressure decline observed in these well patterns has been arrested but that the 400 psig pressure level for all of the producing wells in the project could not be attained by December 31, 1969, and that it would be reasonable to defer to September 30, 1970 the date at which this requirement comes into effect. This date would coincide with the expiry of the 18-month period of the provision contained in clause 5, subclause (2) of the approval.

Baysel submitted that the conversion of the north-easterly producing well in Legal Subdivision 15 of Section 35 to water injection would be consistent with the existing 9-spot injection pattern in the project and would have the effect of preventing any fluid migration between Projects No. 3 and 4. It noted that it is in the area of the proposed injection well that the pressure sink became evident in the 1967-68 period.

SUBMISSION OF INTERVENER

Piute contended that the deferment of the pressure requirement in Project No. 4 would cause further damage to the Piute lease through loss of oil and gas and by migration at the lease boundary. It was the contention of the intervener that the application should be denied since Baysel had not increased the overall rate of fresh water injection nor had it significantly decreased the rate of oil production in Project No. 4. Also, additional deferment of the pressure requirement would extend the period for migration of reservoir fluids into Project No. 4. Piute submitted that the greater pressure transmissibility of the gas saturated areas or the aquifer of the Wainwright Sand would allow fluid in areas such as the Piute Project No. 3, which are outside of Project No. 4 and in contact with the aquifer or the gas saturated area, to continue to migrate toward Project No. 4.

Piute stated that the pressure contours in Project No. 4, as interpreted by Baysel, did not give a representative value of the pressure distribution in the project. It was

the opinion of the intervener that Baysel's isobaric map gave an overly optimistic calculation of the weighted average pressure in the project. Piute stated that the overall decrease in pressures in well patterns 2, 4 and 8 was the result of the project operator using high reservoir pressures in calculating the voidage in the project and of the migration of injected water outside of the pattern areas.

Piute recommended that the withdrawals in Project No. 4 be suspended until a suitable replacement of hydrocarbon withdrawals has been achieved or the weighted project pressure has been restored to 580 psi and that Baysel be instructed to obtain a material balance history for Project No. 4 from 1962 to the present time from an independent consultant.

Piute did not offer any comment with respect to the proposed well conversion to water injection.

VIEWS OF THE BOARD

The Board has reviewed the operation of Project No. 4 since issuance in March, 1969, of Approval No. 1153, having particular regard to the 400 psig pressure requirement. The average project pressure and the replacement ratios for the project and for well patterns 2, 4 and 8, as calculated by Baysel, in the first three quarters of 1969 are illustrated by the following table:

Quarter 1969	Project Average Pressure (psig)	Replacement Ratio			
		Project	Well Pattern		
		4	2	4	8
January - March	359	1.14	3.97	0.86	4.23
April - June	354	1.22	2.47	1.42	2.96
July - September	371	1.06	0.83	1.18	2.30

The Board considers the replacement ratios calculated by Baysel to be somewhat optimistic due to the relatively low shrinkage factor applied to the reservoir hydrocarbon fluids.

In the last six months the decline in project pressure appears to have been arrested, but limited progress has been made in increasing the producing well pressures to the required level. These pressures can be improved either by increasing the amount of water injection or by reducing the amount of production, or both. The Board notes that fresh water injection in the period April - September, 1969 has increased by 4.5 per cent over the

previous six-month period and that oil production has decreased by 13 per cent. The results of Baysel's efforts to increase injection have been minor, and the decline in oil production does not appear to have resulted from an intentional cut back in production rates. The Board is not satisfied that Baysel's efforts to meet the requirements of the approval were as diligent as they might have been. Nevertheless, having regard to Baysel's assurance of an improved water supply and to its proposal to place another well on water injection service thereby increasing the level of fresh water injection to Project No. 4, the Board is prepared to permit the operator to proceed without a requirement at this time that the wells be shut in or the rate of oil production be reduced.

Additionally, the Board is concerned that recently production has not been replaced on a regular basis in well patterns 1, 5 and 6, and that well pattern 2 was not operated in compliance with Approval No. 1153 during the third quarter of 1969. The Board expects that Baysel will not allow this to recur in the future except in the case of an emergency.

With respect to the intervention of Piute the Board notes that currently there does not appear to be a large enough pressure differential between Projects No. 3 and 4 to result in a significant migration of oil and gas between them. Conversion by Baysel of the additional well to water injection should improve the level and uniformity of pressure maintenance in the area, while minimizing the possibility of future oil and gas migration across this boundary. Also, in recent months the operation of Project No. 4 did not appear to be having an adverse effect on the production performance of Project No. 3.

The Board is of the opinion that the 400 psig pressure level target in Project No. 4 is not unreasonable, and that Baysel should be capable of attaining this reservoir pressure by September, 1970. The Board intends to monitor the quarterly pressure survey results submitted by Baysel so that the efforts of Baysel to comply with the pressure requirement of Approval No. 1153 may be assessed on a continuing basis.

DECISION

The Board grants the application and Approval No. 1153 will be amended accordingly.

OIL AND GAS CONSERVATION BOARD

Vernon Millard
Board Member

DATED at Calgary, Alberta
January 6, 1970

structural closures. Quixote stated the gas is prevented from moving into structural highs by areas of low permeability and stratification within the sand. Residual oil saturations in cores of gas wells are, in Quixote's opinion, evidence that the free gas is secondary and occurs throughout the oil zone. Production from the pool may have caused these conditions.

Quixote estimated that the free gas saturation in the reservoir is approximately 10 per cent of hydrocarbon pore volume based on the excess gas produced by adjacent projects one, two, three and four.

Map 1 attached hereto depicts the high gas-oil ratio areas as interpreted by Quixote.

Views of Examiners. The only significant area which produced at low gas-oil ratios under primary depletion in the Provost C Pool was that in Section 18, Township 35, Range 9, West of the 4th Meridian and Sections 13 and 24, both in Township 35, Range 10, West of the 4th Meridian. Most of the wells drilled elsewhere in the field, including wells offsetting the earliest water flood schemes, were believed to have penetrated gas cap sections in the Provost C Pool. Expansion of Project No. 1 (Chevron) has proven this early interpretation to be wrong and has indicated that areas with high initial gas-oil ratios can be successfully water flooded and yield high oil recoveries. Since about 1960 extensive development to the west and east of the original oil production area has occurred. In all of these newer development areas, which include the area of application, initial oil production generally has been at extremely high gas-oil ratios. These areas are now being subjected to water flood and as yet very little response has been obtained and only small amounts of oil have been produced. On the strength of the Project No. 1 experience, however, it is reasonable to assume that oil production response and low gas-oil ratios will eventually ensue in the water flood areas provided initial or subsequent gas saturations are not so high as to preclude development of an "oil bank". In this respect, identification of gas caps and high gas saturation areas is relevant to consideration of the current application for concurrent production.

The examiners have estimated on the basis of drillstem and continuous well production tests, high gas production areas as depicted in Map 1 attached hereto. This interpretation, though it conforms more or less with the interpretation provided by Quixote, lacks quantitative definition of the actual gas saturations present in the gas production prone areas.

In an effort to define gas saturation and oil saturation levels, the examiners have reviewed and attempted to interrelate the evidence provided by well tests, sand structural

interpretations, oil saturation measurements in core analyses, sand characteristics as indicated by cores and logs, and initial and current reservoir pressures.

Initial tests of the wells in Legal Subdivision 4 of Section 29 and Legal Subdivision 15 of Section 2, in Township 35, Range 9, West of the 4th Meridian in the early 1950's recorded 2 to 3 million cubic feet per day of gas with no oil production, thus indicating "gas caps" in those areas. However, wells drilled in Legal Subdivision 6 of Section 29 and Legal Subdivision 13 of Section 2 in the same Township, both at structurally equivalent positions to the offset "gas cap" wells, produced oil at 40 barrels per day at a GOR of 1500 cubic feet per barrel and 15 barrels per day at a GOR of 10,000 cubic feet per barrel respectively. Similarly, the wells in Legal Subdivision 15 of Section 21 and Legal Subdivision 14 of Section 21 produced only gas at 1 to 2 million cubic feet per day on short tests. However, a small amount of liquid was produced on the tests by both wells and, as well, the core analyses indicated residual oil saturations of about 15 per cent, a level as high as that of relatively low gas-oil ratio wells in the area. Moreover, if these wells were gas wells with no oil saturation it is probable, having regard for the amount and character of the sand, that the gas production rates would be in the neighbourhood of 5 to 10 million cubic feet per day rather than the 1 to 2 million cubic feet per day actually recorded. Based on the foregoing evidence, the examiners conclude that short term well production tests are unreliable for the purpose of defining gas cap or high gas saturation areas within the area of application.

Examination of cores indicates that there is some interbedding of nonpermeable shale strata and limey sand strata in the upper and lower parts of the gross pay section. There is, however, a persistent massive sand section in the middle part of the gross pay section (representing some 70 per cent of the net pay) which usually contains no nonpermeable laminae. The sand, fine grained and poorly consolidated, exhibits permeabilities in the range of 100 to 400 millidarcies. Thus it appears that there are for the most part no impermeable barriers within the main productive sand section which might cause local trapping of gas. In this respect, the examiners do not agree with Quixote's view that the degree of gas saturation can be related to local trapping effects caused by shale or limey sand barriers.

The examiners have reviewed structural interpretations of the sand and confirm that the so-called gas cap areas are not consistently related to crestal areas as now interpreted. On the basis of a couple of twin wells drilled in the area,

the examiners conclude that structural relief of the sand can change very rapidly (i.e. 10 to 20 feet within a distance of 150 feet) whereas the present structural interpretation provides for only about 20 feet per mile local relief and 7 feet per mile regional structure. It thus appears that the top of the sand is structurally very irregular and that the existing well density does not permit an accurate interpretation of that structure.

Reservoir pressures measured in November 1969 indicate that the pressure in the eastern part of the area of application is in excess of 800 pounds per square inch gauge whereas pressures grade downward to as low as 650 pounds per square inch gauge on the western edge of the area of application. This pressure distribution supports the concept that production taken from the long established oil production area around Section 13, Township 35, Range 10, West of the 4th Meridian has caused a pressure sink to occur in that area which extends outwards into the previously undeveloped areas. The examiners estimate that evolved gas would occupy about 8 per cent of pore volume as a result of pressure declining from the initial level of 850 pounds per square inch gauge to a level of 650 pounds per square inch gauge. The examiners believe that the equilibrium gas saturation for this type of sand is around 3 per cent, so that gas saturation in excess of this amount would tend to migrate to the crestal positions. Having regard for the pressure condition and the gas saturation phenomena, it appears that the western portion of the area of application contains a significant free gas phase both dispersed in the oil zone and trapped in crestal positions.

Consideration of all of the evidence leads the examiners to the conclusion that present gas saturations in the area of application are sufficiently high to lead to high gas production from some wells but are not likely indicative of gas cap areas devoid of recoverable oil. The examiners believe it is probable that a gas saturation of about 5 per cent of pore volume exists throughout much of the area of application and it may be 20 to 30 per cent of pore volume in certain local structural crests.

MERIT OF SCHEME

Views of Quixote. Quixote expressed the view that concurrent production of the oil and gas will not adversely affect ultimate oil recovery since all reservoir withdrawals will be replaced by water injection. It anticipates that any oil which invades high gas saturation areas would not be lost via a gas cap wetting effect because the high gas saturation areas have indicated significant residual oil saturations in core analyses. As a safeguard against possible oil losses by oil migration into

gas cap areas, Quixote suggested that well rates be controlled by assigning GOR penalties of Table 5000 on an individual well basis.

Quixote further stated that it considered the gathering of the gas production economically feasible and that it believed the gas could be processed and marketed on satisfactory terms.

Views of Examiners. The examiners believed that it will not be feasible to redissolve the gas into the oil in those areas with high gas saturations (i.e. 20 per cent or more). On this basis, the examiners conclude that the only feasible way of depleting the hydrocarbons from the pool without the drilling of unnecessary wells is to permit the production of high gas saturation areas at this time, provided that such production will not significantly increase the gas saturations in such areas through the development of pressure sinks. The occurrence of significant pressure sinks could lead to increases in the level of gas saturation and this in turn may promote the fingering of water into these areas resulting in reduced volumetric sweep efficiency. In the extreme case this could result in complete failure of the water flood process. Therefore, it would be inappropriate to extend concurrent production to areas subject to primary depletion.

The examiners believe that two specific control measures would be needed to prevent excessive withdrawals and development of pressure sinks. One measure would be that of restricting individual well production by the application of Table 5000. This provision was agreed to by Quixote during the hearing. A further control measure of significance to the ultimate success of the water flood scheme would be to require replacement of withdrawals on a segment basis. For control purposes the inverted nine-spot water flood pattern can be divided into appropriate segments as shown on Map 2. While this control measure was not discussed at the hearing, the examiners are satisfied that it is inseparable from the matter of concurrent production and thus should be implemented if concurrent production is granted.

RECOMMENDATIONS OF EXAMINERS

The examiners recommend the following:

1. That the scheme of concurrent production be approved for the area subject to Approval No. 1079 as outlined on Map 2 by appropriate amendment to the approval.

2. Except for wells defined as control wells, that individual well withdrawal rates be restricted to rates which each well would be permitted in accordance with Table 5000.

3. That the approval require that the gas not required for lease fuel be gathered and marketed.

4. That Approval No. 1079 be amended to require that a monthly injection-withdrawal balance satisfactory to the Board be maintained for each segment where the segments comprise areas such as are illustrated on Map 2.

5. That each progress report submitted for the water flood scheme contain an assessment of the effect that concurrent production has had on the efficiency of the flood.

VIEWS OF THE BOARD

The Board agrees with the views of the examiners.

DECISION

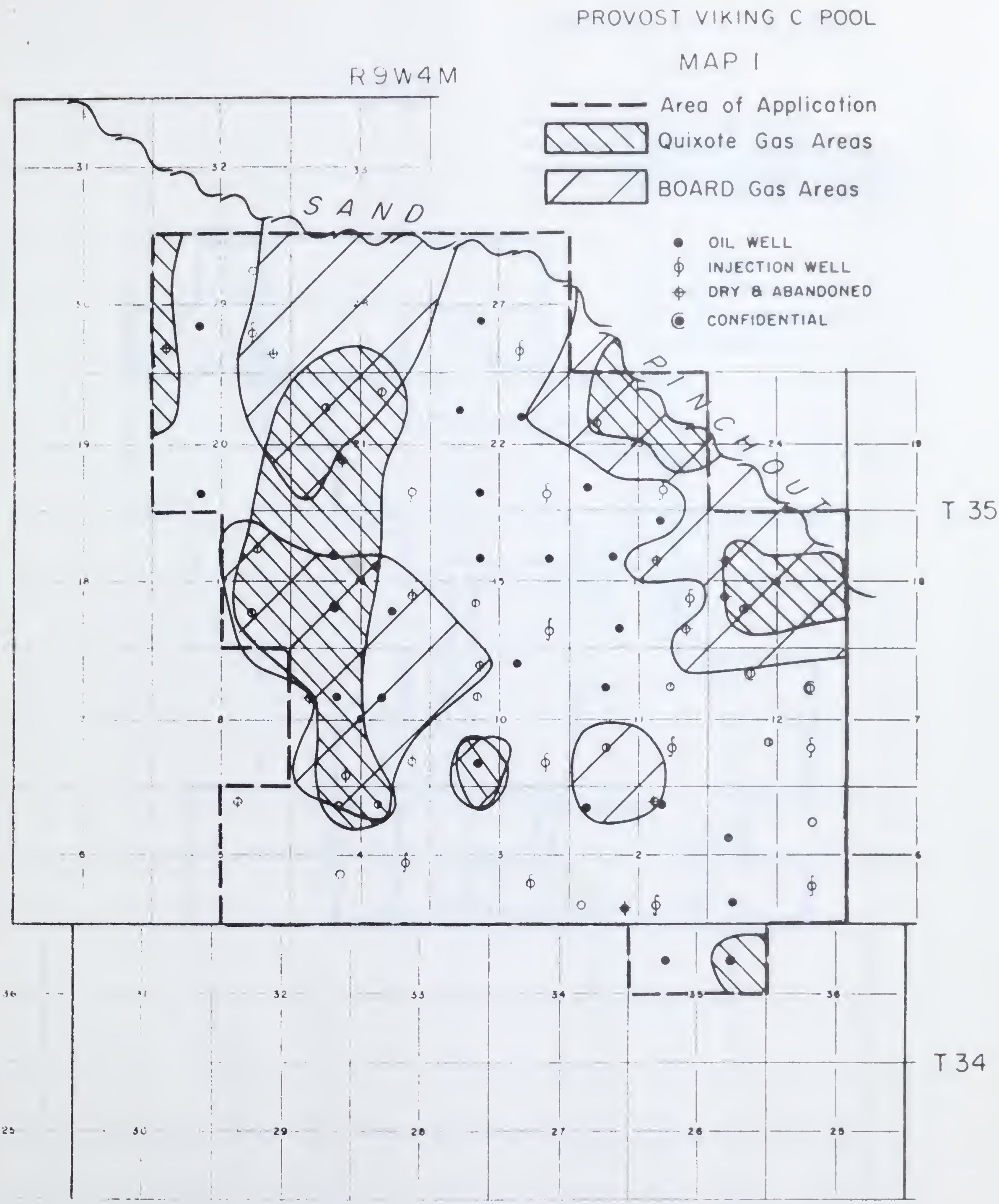
An approval, superseding Approval No. 1079, and in accordance with the recommendations of the examiners, shall be issued.

OIL AND GAS CONSERVATION BOARD

Vernon Millard

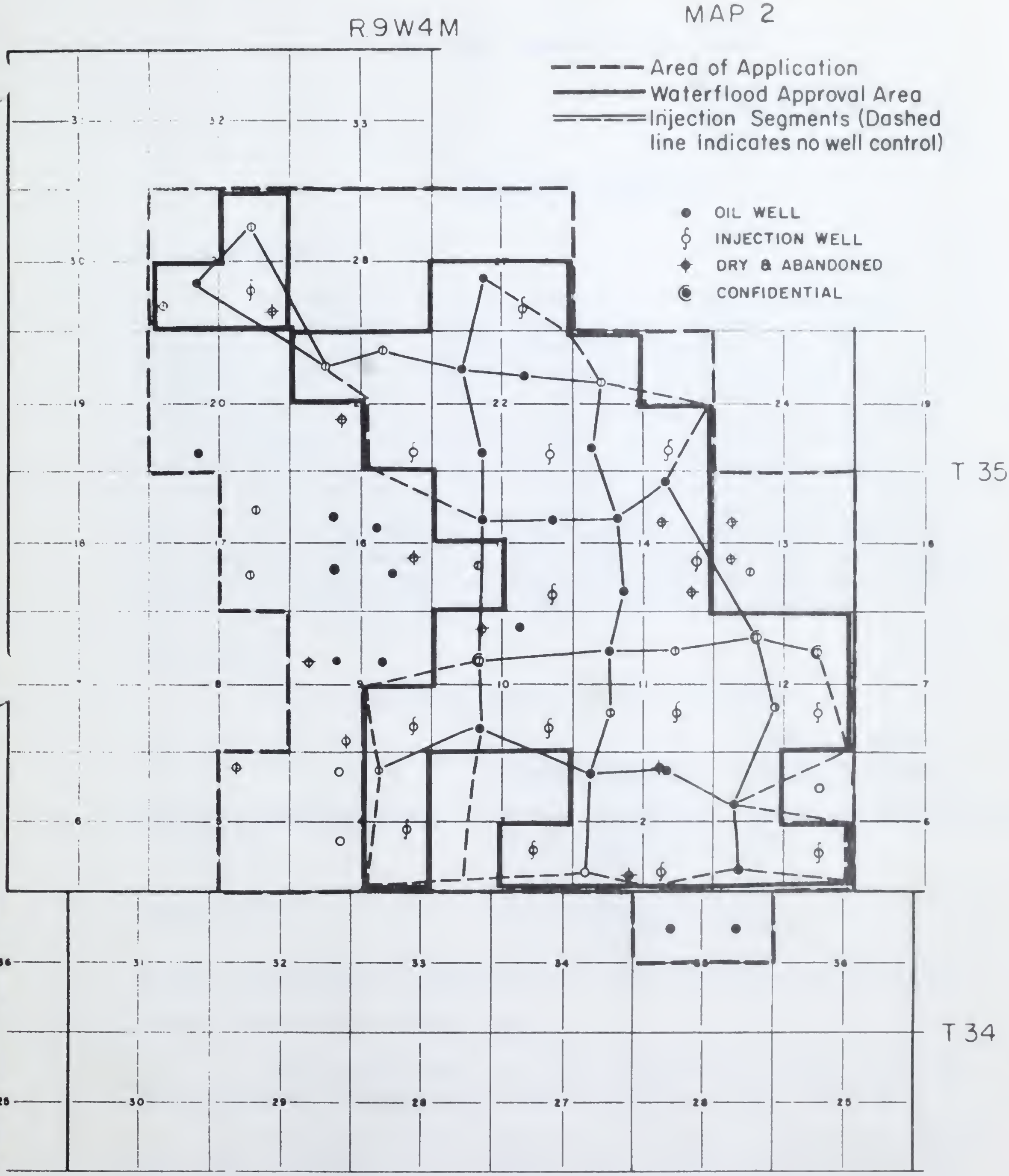
Vernon Millard
Board Member

DATED at Calgary, Alberta
March 17, 1970


PROVOST VIKING C POOL
MAP I
R9W4M
Area of Application
Quixote Gas Areas
BOARD Gas Areas
OIL WELL
INJECTION WELL
DRY & ABANDONED
CONFIDENTIAL
SAND
PINCHOUT
T 35
T 34

PROVOST VIKING C POOL

MAP 2



OIL AND GAS CONSERVATION BOARD

Decision 70-3
Proceeding No. 5050

PERMIT NO. CH 65-1

THE PROCEEDING

The Board, with the approval of the Lieutenant Governor in Council, issued Permit No. CH 65-1, dated September 17, 1965, authorizing the removal from the Province of some 7.1 million barrels of propane to be transported from the Province of Alberta to the Province of British Columbia through a pipe line to be constructed by Hydrocarbons Pipeline Limited. The permit included several performance conditions by various dates. The permittee failed to satisfy certain of these conditions and the Board, on its own motion, called the hearing under section 13 of The Gas Resources Preservation Act, 1965, to hear representations as to whether Permit No. CH 65-1 should not be cancelled. The hearing took place on May 26, 1970, with A. F. Manyluk, P. Eng. and V. Millard, sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Canadian Hydrocarbons Limited	W. A. Troughton G. M. Miller, P. Eng. J. G. Spratt	Canadian Hydrocarbons
Board Staff	N. A. Macleod, Q.C. G. J. DeSorcy, P. Eng.	

No one else filed a submission or appeared at the hearing.

SUBMISSION OF THE BOARD STAFF

The Board staff, in its submission, summarized the circumstances leading up to the calling of the hearing.

Canadian Hydrocarbons by application dated September 25, 1964, applied to the Board for a permit authorizing the removal from the Province of 15 million barrels of propane over a 20-year period beginning October 31, 1966. The propane

was to come from the Harmattan Area gas processing plant and was to be transported from the Province of Alberta to the Province of British Columbia through a pipe line to be constructed by Hydrocarbons Pipeline Limited.

The Board, with the approval of the Lieutenant Governor in Council, issued Permit No. CH 65-1, dated September 17, 1965, authorizing the removal from the Province of some 7.1 million barrels of propane over the 20-year period commencing November 1, 1966. Canadian Hydrocarbons by application dated January 25, 1966, requested an amendment to its permit increasing the volume authorized for removal from the Province. The application for amendment was subsequently withdrawn.

Clause 4 of Permit No. CH 65-1, as amended by stipulation pursuant to Permit No. CH 65-1 dated February 22, 1966, states as follows:

"4. The Permittee shall satisfy the Board prior to August 31, 1966, that arrangements have been completed for financing the construction of any required transportation facilities and that construction will commence not later than October 31, 1966, unless, upon application by the Permittee, later dates are stipulated by the Board."

Clause 5 of the permit states:

"5. The effective commencement of removal of propane from the Province pursuant to this Permit shall be on or before December 30, 1966, unless, upon application by the Permittee, a later date is stipulated by the Board."

The Board staff submission stated that Canadian Hydrocarbons had not, as of April 16, 1970, satisfied the Board that arrangements have been completed for financing the construction of required transportation facilities, had not commenced construction of the transportation facilities, and had not removed propane from the Province pursuant to the subject permit.

SUBMISSION OF CANADIAN HYDROCARBONS

Canadian Hydrocarbons did not make a written submission prior to the hearing. Mr. Spratt, President and Director of Hydrocarbons Pipeline Limited, made a statement on behalf of the permittee. Mr. Spratt stated that, following issuance of Permit No. CH 65-1 in September, 1965, application

was made to the National Energy Board for permission to construct a products pipe line from south-west Alberta to the Pacific coast. The application was rejected by the National Energy Board. According to Mr. Spratt, Canadian Hydrocarbons has since that time made several attempts to re-activate the project either by way of increasing its own export markets or by getting others to become associated with the project. Mr. Spratt stated that although Canadian Hydrocarbons has considerably expanded its export markets for propane the transportation has been by tank car or truck. He stated that Canadian Hydrocarbons could see no possibility of developing the pipe line project in the immediate future and with that in mind should not ask for a further extension of Permit No. CH 65-1.

FINDINGS OF THE BOARD

The Board, having considered the submission of the Board staff and the statement of Canadian Hydrocarbons, finds that clauses 4 and 5 of the terms of Permit No. CH 65-1 have not been complied with. It finds further that there is little likelihood that the terms can be satisfied in the near future.

DECISION

The Board, with the approval of the Lieutenant Governor in Council, is prepared to cancel Permit No. CH 65-1.

OIL AND GAS CONSERVATION BOARD

Frank M. Manyluk

A. F. Manyluk
Deputy Chairman

DATED at Calgary, Alberta
June 2, 1970

(NOTE:- The Lieutenant Governor in Council having given his approval by Order in Council numbered O.C. 1071/70 dated June 9, 1970, the subject Permit is cancelled.)

OIL AND GAS CONSERVATION BOARD

Decision 70-4
Application No. 4869

APPLICATION FOR GOR PENALTY RELIEF
PEMBINA CARDIUM POOL

THE APPLICATION AND HEARING

Canada-Cities Service Petroleum Corporation applied for the basing of gas-oil ratio (GOR) penalties in part of the Keystone area of the Pembina Cardium Pool on net gas production where the net gas production would be the difference between gross gas production and the gas conserved or used as lease fuel.

The application was heard on April 14, 1970, by the Board, with G. W. Govier, P. Eng., Vernon Millard and D. R. Craig, P. Eng. sitting.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Canada-Cities Service Petroleum Corporation	G. Dohy, P. Eng. K. Baher, P. Eng.	Cities Service
Mobil Oil Canada, Ltd.	D. D. Brown, P. Eng. G. C. M. Derbowka, P. Eng.	Mobil
Board Staff	D. G. Pearson, P. Eng. S. Koles, P. Eng.	

THE ISSUES INVOLVED

Consideration of the application involved the matters of:

1. Area of Application

    (1) Conservation

    (2) Correlative Rights

2. Pool Wide Implication of the Proposed Operation

AREA OF APPLICATION

(1) Conservation

Views of Cities Service. Cities Service submitted that the performance of the pilot gas injection scheme conducted in 1959 and the two water flood projects immediately to the west of the area of application demonstrated that under present technology, the only feasible method of exploiting the area of application at its present stage of pressure decline is by primary depletion. To support this statement Cities Service submitted a study of the results of the performance of the pilot project entitled "A Reservoir Engineering Study, Cardium Sand - Keystone Area, Pilot Gas Injection Project, Pembina Field" dated July 1964. This study concluded that ultimate recoveries of only 2.85 per cent and 4.88 per cent would be obtained by gas flood and water flood respectively as compared with Cities Service's estimate of 8.3 per cent by primary depletion.

Concerning the adjacent water flood projects to the west, Cities Service stated that an oil bank generally indicative of a successful water flood, has not been formed in these projects and that oil productivity has been lost upon water breakthrough. It further stated that the area of application contained a significantly higher proportion of conglomerate in the pay section which would make the area of application even less amenable to water flooding than the areas of the adjacent projects.

Cities Service estimated, by extrapolation of productivity, the primary recovery for the area of application to be seven per cent of the oil in place of 215 million stock tank barrels (MMSTB) under the present GOR penalty restriction and 8.3 per cent or an increase of 2.7 MMSTB under the proposed GOR penalty relief. It stated that the wells were productivity limited and could not be produced at rates that would be detrimental to primary recovery.

Cities Service explained that most of the gas produced from the area of application is being conserved and that an additional incentive would exist to gather more of the gas if GOR penalty relief was approved. Cities Service made no representation regarding the manner of control to be applied to the area of application to ensure maximum conservation of the gas but stated that it would be reasonable if flaring were limited to five per cent of the produced gas.

Cities Service contended that if implementation of the proposed operation was delayed and the area continued to be depleted under the present mode of operation, a considerable number of wells would be prematurely abandoned as a result of the GOR penalties imposed on the oil production. It stated that, while the delay would have no effect on oil recovery, there would be an effect on gas conservation since it would not be feasible to gather gas from the marginal wells.

Views of Mobil. Mobil had no objections to the proposal.

Views of the Board. The Board agrees with Cities Service that the presently known enhanced recovery methods can not be applied successfully because of the severe stratification caused by the high permeability conglomerate section overlying the low permeability sand section in the area. The Board is satisfied that at the present time continued primary depletion is the only feasible method of exploiting the area and that GOR penalty relief appears necessary to avoid abandonment of wells on account of GOR penalty restrictions. Since some of the wells are already restricted to their economic limit and others are approaching it rapidly, GOR penalty relief should be granted now. The Board agrees that the produced gas should be gathered.

The Board considers it necessary that there be some means to control the amount of gas flared. While the Board agrees with Cities Service that a flaring restriction of five per cent of the produced gas is reasonable, the Board believes that the calculation of GOR penalties based on net gas production would be administratively simpler. For this purpose the Board believes it appropriate that the GOR penalties be determined by applying the net gas production of each well to Table 200 of Schedule 6, Part A of the Oil and Gas Conservation Regulations where net gas production is defined as the difference between the gross gas production and marketable gas delivered for sale.

(2) Correlative Rights

Views of Cities Service. Cities Service claimed that the Board's normal control well restrictions would give adequate protection of correlative rights along lease boundaries. It expressed the opinion that the proposed penalty relief would not cause fluid migration from the water flood areas to the area of application since experience in the water flood schemes indicated water breakthrough and a decline in productivity. Cities Service explained that the adjacent water flood projects were not successful schemes and a corridor to protect them was not necessary.

Cities Service further suggested that to maintain equity between wells the GOR penalties to be applied to each control well defined by the Oil and Gas Conservation Regulations be determined on the same basis as it is for the offsetting well causing the control well status.

Views of Mobil. Mobil submitted that a pressure gradient is created where a pressure maintenance project is operated adjacent to an area under pressure depletion. Mobil contended that the operation proposed by Cities Service would increase this pressure gradient and thereby the fluid migration, resulting in even greater inequity. Also it stated that effective pressure maintenance of its project would be difficult. Mobil requested that its Pembina Project No. 84 be protected by a one mile corridor wherein normal GOR penalties would continue to apply.

Views of the Board. The Board concludes that the proposal would tend to increase the pressure gradient between pressure maintained and primary depletion areas and that some sort of protection should be provided for the pressure maintenance area along the lease line boundaries. The Board agrees with Mobil that a one-mile corridor wherein normal GOR penalties would continue to apply would be appropriate.

The Board agrees with Cities Service that the GOR penalties for control wells should be determined on the same basis as it is for the offsetting well causing the control well status.

POOL WIDE IMPLICATION OF THE PROPOSED OPERATION

The notice of hearing made reference to the implications that the application may have on a pool-wide basis. In particular the Board was concerned with the effect similar requests for GOR penalty relief would have on conservation and correlative rights and on the offset enhanced recovery schemes. This matter was also discussed at the hearing.

Views of Cities Service. Cities Service contended that if pressure maintenance was impractical in other areas in the pool now subject to primary depletion and a gain in conservation would be achieved by an operation similar to that proposed by Cities Service, then such areas should be permitted to produce under a net GOR penalty.

Views of Mobil. Mobil expressed the opinion that the pool wide implication of the proposal could not be generalized and that each future application would have to be considered on its merits.

Views of the Board. The Board agrees with Cities Service and Mobil that the pool-wide implications of the application can not be generalized and that future applications will have to be considered in the light of all circumstances and on their own merits.

DECISION

The Board grants Cities Service's application for GOR penalty relief for that part of the Pembina Cardium Pool described in the application subject to the following conditions:

1. The GOR penalties for each well not designated as a control well shall be obtained by applying the GOR determined using the net gas production of each well to Table 200 of Schedule 6, Part A of the Oil and Gas Conservation Regulations, where net gas production is defined as the difference between the gross gas production and marketable gas delivered for sale.

2. The production rates from wells within one mile of the boundary of an enhanced recovery scheme shall be subject to the normal GOR penalties schedule.

3. The GOR penalties to be applied to each control well defined by the Oil and Gas Conservation Regulations and within the subject area shall be determined on the same basis as it is for the offsetting well causing the control well status.

The within decision will be implemented in the Board's MD orders effective on and after August 1, 1970.

OIL AND GAS CONSERVATION BOARD

G. W. Govier
Chairman

DATED at Calgary, Alberta
June 25, 1970

OIL AND GAS CONSERVATION BOARD

Decision 70-5
Application No. 5076

INCLUSION OF THE RAINBOW KEG RIVER EEE POOL WITHIN INTEGRATED SCHEME NO. 1

THE APPLICATION AND HEARING

Banff Oil Ltd. applied under The Oil and Gas Conservation Act, 1969, to have the Rainbow Keg River EEE Pool (also referred to herein as the "EEE Pool") added to Integrated Scheme No. 1 as an active solvent flood pool, with the crude oil allowable which would normally be allocated to the Rainbow Keg River EEE Pool added to the Integrated Scheme No. 1 aggregate allowable.

The application was heard on May 28, 1970, by the Board with G. W. Govier, P. Eng., A. F. Manyluk, P. Eng. and Vernon Millard sitting.

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Banff Oil Ltd.	A. D. Bradshaw, P. Eng.	Banff
Imperial Oil Limited	D. P. Bossler, P. Eng.	Imperial
Board Staff	J. A. Bray, P. Eng.	

After a public hearing of Application No. 4109, the Board approved Integrated Scheme No. 1 and issued Approval No. 1133 authorizing sequential solvent displacement of the recoverable oil reserves of the Rainbow Keg River A Pool, Rainbow Keg River D Pool, Rainbow Keg River E Pool, Rainbow Keg River G Pool, Rainbow Keg River H Pool and Rainbow Keg River O Pool.(1) Also after a public hearing the Board authorized, through Approval No. 1263, solvent displacement of the Rainbow Keg River EEE Pool.

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(1) See Decision 69-1.

DEFINITION OF THE ISSUES INVOLVED

The issues to be resolved in the current application relate to satisfying the Board, pursuant to section 34, subsection (2) of The Oil and Gas Conservation Act, 1969, that

(a) integration of the subject pool results in significant conservation advantages,

(b) the applicant has made an undertaking to proceed with the scheme or with an alternate scheme that will result in equivalent or greater recoveries, and

(c) the reserves to be recovered from each of the pools in the integrated scheme may be estimated with a reliability comparable to that in the case of single pools not produced under an integrated scheme.

VIEWS OF THE APPLICANT

Banff stated in its submission that integrated operation of the EEE Pool within Integrated Scheme No. 1 was in the best interests of conservation. Banff believes that such inclusion would provide flexibility in allocating production allowables among the active solvent flood pools of the scheme and in utilizing the available solvent and gas in the most efficient manner.

Banff further stated that utilization in Integrated Scheme No. 1 of the high productivity available due to the excellent reservoir characteristics of the EEE Pool would help reduce undesirable pressure drawdowns in the Rainbow Keg River A Pool and the Rainbow Keg River O Pool, and would thereby improve the overall recovery of the scheme. In its submission, during peak allowable months, the allowable of Integrated Scheme No. 1 will be greater than the combined productive capacity of the Rainbow Keg River A Pool and the Rainbow Keg River O Pool.

Under examination the applicant indicated that it was difficult to quantify the incremental conservation gains attributable to inclusion of the EEE Pool within the integrated scheme inasmuch as the EEE Pool is now undergoing solvent flood outside of the integrated scheme. The applicant stated that additional producing wells are planned for the integrated scheme and that inclusion of the EEE Pool within the integrated scheme would provide greater flexibility of selecting locations and would also permit some deferment of drilling costs.

Under examination the applicant also stated that inclusion of the EEE Pool did not have much relationship to the possible future solvent flooding of the Rainbow Keg River B Pool and Rainbow Keg River F Pool, but what relationship there is, is favorable. Banff also stated that the EEE Pool would definitely have been included in the original application if sufficient information had been available at that time.

VIEWS OF IMPERIAL

Imperial intervened in support of the application and expressed the view that whether the EEE Pool was solvent flooded within or out of the integrated scheme, the ultimate recovery from the pools concerned "would be at least as great". Imperial further contended that approval of the application would cause no loss of the market share of other pools in the Province. It said that where economic resources are conserved, the applicant should be allowed the requested production flexibility. Imperial stated at the hearing that its intervention was "guided by what we consider to be a reasonable basis for inclusion or not of a pool in an integrated scheme, so we are not looking specifically at the requirements as set out in the Act for an integrated scheme".

VIEWS OF THE BOARD

Having considered the submissions and evidence from the hearing the Board is of the opinion that:

1. Inclusion of the Rainbow Keg River EEE Pool within Integrated Scheme No. 1 fulfils the requirements of Issues (a) and (b). The integrated scheme now proposed by the applicant will result in at least equivalent recoveries and there is reasonable expectation that the amendment applied for will provide an oil conservation gain. The Board accepts the applicant's undertaking to proceed with the integrated scheme, amended to include the Rainbow Keg River EEE Pool, to the depletion of the pools. In addition, the Board believes that inclusion of the Rainbow Keg River EEE Pool within the integrated scheme will not prejudice the possible future solvent flooding of the Rainbow Keg River B Pool or the Rainbow Keg River F Pool.

2. The recoverable reserves of the Rainbow Keg River EEE Pool were established after consideration of the evidence presented at a public hearing of Application No. 4748 to solvent flood the Rainbow Keg River EEE Pool. The reliability of this recoverable reserves determination fulfils the requirements of Issue (c).

Further, the Board is of the opinion it would have included the Rainbow Keg River EEE Pool within the original integrated scheme if the Rainbow Keg River EEE Pool had been part of the original application. Additionally, there may be some modest deferment in capital expenditures for additional producing wells if the Rainbow Keg River EEE Pool is included within the integrated scheme. The Board concludes that such additional drilling would be clearly economic and that oil allowables and production rates of the concerned pools would remain the same, with or without integration of the Rainbow Keg River EEE Pool.

DECISION

The Board approves the inclusion, effective August 1, 1970, of the Rainbow Keg River EEE Pool within Integrated Scheme No. 1. Approval No. 1263 relating to the Rainbow Keg River EEE Pool will be rescinded and the terms and conditions therein will be inserted into Approval No. 1133.

OIL AND GAS CONSERVATION BOARD

G. W. Govier
Chairman

DATED at Calgary, Alberta
July 6, 1970

OIL AND GAS CONSERVATION BOARD

Decision 70-6
Proceeding No. 5086

INITIAL RESERVE ASSIGNMENT RAINBOW-ZAMA AREA

PROCEEDING

The Board staff proposed a change in the method of initial crude oil reserve assignment for new Keg River oil pools in the Rainbow-Zama area in northwestern Alberta. It asked that the initial reserve assignment be based on a rock volume of 3,000 acre-feet for new Keg River oil wells within the Zama basin in a certain defined area. The staff further suggested that a rock volume of 11,000 acre-feet may be appropriate for the same purpose in a certain defined area within the Rainbow basin.

A public hearing to consider the proposal and submissions of interested persons was held by the Board on July 15, 1970, with G. W. Govier, P. Eng., A. F. Manyluk, P. Eng., and D. R. Craig, P. Eng., sitting.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Board Staff	R. G. Evans, P. Eng. W. H. Wolff, P. Eng. N. G. Berndtsson, P. Eng.	Board Staff
Mobil Oil Canada, Ltd.	D. D. Brown, P. Eng.	Mobil
Chevron Standard Limited	J. R. Lishman	Chevron
Sun Oil Company	R. C. Egglestone, P. Eng.	Sun
Hudson's Bay Oil and Gas Company Limited	J. H. McKibbon, P. Eng. F. D. Kirkham	Hudson's Bay
Apache Oil Corporation	T. J. Harp, P. Eng.	Apache
Canex Aerial Exploration Ltd.	D. Priestman	
Petro Lewis Corporation Canus Petroleum Limited J. M. Huber Corporation Pioneer Exploration Ltd. Voyager Petroleums Ltd.	D. J. Fraser, P. Eng.	

Lakeshore Exploration Ltd.	D. J. Fraser, P. Eng.	Lakeshore
Banff Oil Ltd.	A. D. Bradshaw, P. Eng.	Banff
Canadian Superior Oil Ltd.	R. W. Stanich, P. Eng.	Canadian Superior
Texaco Canada Limited	J. G. Pashniak, P. Eng.	Texaco Canada
Dome Petroleum Limited	C. S. Dunkley, P. Eng.	Dome
Imperial Oil Limited	D. P. Bossler, P. Eng.	Imperial

INTRODUCTION

In calculating the reserves of discovery and early follow-up oil wells, the Board's practice is to initially assign the area of the well's drilling spacing unit, which generally is 160 acres. If other information, such as well control and geological information, is available at the time the well commences production it may be used in determining the area for the reserve assignment. As soon as more information, such as pressure and production data, seismic data, well control, reservoir limit tests, and so forth, becomes available or is presented to the Board the reserve assignment may be reviewed. These reviews may be initiated by either the Board staff or any operator in accordance with the Board's Informational Letter IL No. 68-15.

The Board reviewed its policy on the area assignment at the February 1968 Reserve Hearing (Proceeding No. 3700) and decided to not make any changes to its policy (Decision 68-9). The Board concluded at the time that the assignment of an area of one drilling spacing unit to a discovery or early follow-up oil well had more advantages, including administrative simplicity, than disadvantages compared with any of the other proposals made, provided adequate pressure-production data were obtained in the early life of the pool on which to base a reappraisal of the reserves.

PROPOSAL OF BOARD STAFF

(1) Views of Board Staff

The existing method of initial reserves assignment to new pool wells in the Rainbow-Zama area, which involves the arbitrary assignment of 160 acres as the area of the pool, was seriously questioned by the Board staff. It contended that this 160 acre assignment, when combined with wellbore pay thickness, porosity, and like data, yielded an initial reserves assignment for many of the pools in the Rainbow-Zama area which was too large. The staff study purported to show that sufficient evidence is now available to allow one to make a more suitable first estimate of the pool size. Heretofore the Board's practice has been to review the initial reserves assignment after approximately nine months of production. At this stage, produc-

tion and pressure data normally became available to allow material balance calculations to be made with a fair degree of reliability in many cases. The general trend has been toward substantial reductions in pool reserves, particularly in the case of single well pools and particularly in the Zama basin. However, some pools within both the Rainbow and Zama basins do not lend themselves to material balance analysis, usually because of a significant water drive or a large gas cap in association with the oil pool, or because of pressure interference between pools. In some of these cases the operators have supplied evidence, usually seismic data, to allow redetermination of pool reserves. In other pools, no such redetermination has been possible. In the opinion of the Board staff significant detrimental effects to both conservation and equity result from the erroneous reserves assignments. Furthermore the extensive reviews and significant changes to reserves have imposed a substantial administrative work load on the Board staff and industry. Initial reserves assignments which more closely approximate the true reserves would presumably reduce this load.

The Board staff study involved a statistical evaluation of the evidence available on the pools within the Rainbow-Zama area. For each pool the staff assessed whether or not a reliable determination of reserves was available, as a result of studies based on material balance calculations, seismic data, follow-up wells, or other data. It was found that reliable estimates were available from approximately half of the wells within each basin. The statistical evaluation included study of apparent pool area at the oil-water interface, crestal area, thickness, porosity and oil zone rock volume. An initial subdivision of the total Rainbow-Zama area into two parts, the southern part being called the Rainbow basin and the northern one the Zama basin, was made on the basis of geological conditions in the area, and this subdivision was confirmed by differences in the statistical results obtained.

With respect to the statistical evaluations using the oil-water contact area and the crestal area, the Board staff found that no reliable conclusions could be reached. Within each basin, the thickness and porosity evaluations showed distinct and fairly reliable trends. The Board staff believed, however, that these conclusions should not be applied in initial reserves determination because it would discourage the taking of data.

The data on pool rock volume for the Zama basin exhibited a definite sharp-peaked, non-symmetrical distribution. In the opinion of the Board staff, the data were best fit by a lognormal frequency equation, and the "best fit" lognormal curve had a mode value of 3,050 acre-feet, a median value of 7,170 acre-feet and a mean value of 10,980 acre-feet. The Board staff recognized advantages to choosing both the mode and median values, but reasoned that the mode value best represented the size of pool most likely to be discovered within the area, and

recommended that the Board adopt a value of 3,000 acre-feet for initial reserves assignment for new pools within the area.

For the Rainbow basin the data indicated a similar non-symmetrical distribution of pool volumes, but the peak was broader and the statistical tests less definite in selecting the type of distribution. The Board staff, however, concluded that the data were adequately represented by a frequency distribution curve of the gamma type and that the "best fit" gamma curve had the characteristics of a mode value of 10,650 acre-feet, a median value of 23,000 acre-feet and a mean value of 28,800 acre-feet. The Board staff concluded that the mode value of about 11,000 acre-feet would best represent the size of pool most likely to be discovered within the Rainbow basin. Nevertheless, the staff reasoned that, because the data and statistical analysis yielded results of a rather poorly defined nature, because the use of the gamma distribution function is somewhat unconventional and perhaps controversial, and because the application of the mode value results in an initial rock volume not too different from that obtained from the 160 acre assignment, a sufficient basis for change in the existing method of initial reserves assignment did not exist. The Board staff therefore suggested, but did not specifically recommend, the mode value of 11,000 acre-feet as a possible new basis for reserves assignment, in order that the views of the industry could be obtained.

In the view of the Board staff, the rock volume assignments based on the statistical studies could be used for initial reserves determination in new pools, and also for adjustment of assigned reserves in those older pools where a more definitive evaluation on the basis of specific pool studies was not available or possible. As an alternative to the adoption of the statistical conclusions for initial reserves assignment, the Board staff witness agreed that the data could be used for subsequent reserves assignment, perhaps after a nine to twelve month evaluation period, in default of other more specific methods being available and useful to define pool reserves.

The Board staff contended that both conservation and equity advantages would be obtained by adoption of the new approach. It expressed the opinion that these were of approximately equal importance. A more equitable distribution of allowable within the Province would result because a more reliable estimate of initial reserves was possible. With respect to conservation, the Board staff speculated that reservoir damage due to coning of water or gas had occurred in a significant number of pools already, and that this was partly due to the disproportionately high allowables which had resulted from the initial reserves assignments. Adoption of the proposal would result in avoidance of this type of reservoir damage.

The Board staff suggested that, on the basis of very general geological considerations, similar conditions for development of Keg River reef structures and accumulation of oil extended for a considerable distance around the now developed fields. For purposes of application of the statistical conclusions, the staff recommended blocks of 56 townships and 80 townships for the Zama and Rainbow basins respectively, extending from 1 to 30 miles, and averaging roughly 15 miles, beyond the existing field boundaries.

The Board staff agreed that more detailed and extensive studies involving time series analysis, statistical or geological studies might be able to provide better definitions of appropriate pool size.

(2) Views of Mobil

Mobil did not express an opinion on the validity of the Board staff findings but it did disagree with the proposed use of the findings. Mobil contended that in the interests of equity, studies of pool size would be necessary for all pools in the Province where 160 acres does not give a reasonable approximation of pool reserves. This would negate the administrative advantage of using 160 acres for initial reserves. Also use of statistical methods cannot be made until a considerable number of pools have been developed, consequently it would generally be too late to apply such findings, because only a few pools would remain to be found. Mobil considered this to be the case in the Rainbow and Zama basins.

Mobil was of the opinion that the Board staff's concern regarding conservation should not be related to the initial reserve assignment. Conservation aspects involving reservoir damage caused by excessively high allowables should be handled by engineering considerations. Determining proper reserves is an equity issue because reserves are the basis of the proration plan which is an equity device.

(3) Views of Hudson's Bay

Hudson's Bay considered the assumption implicit in the Board staff study, that the pools in the Zama, Virgo, Larne and Amber Fields are within a common statistical population, to be invalid and contended that the results can only be used within each field on an individual basis. Only a few new pools will be discovered in the presently defined limits of the fields, thus limiting the use of the proposed method. Further, Hudson's Bay thought it was improper to apply the statistical results to a larger area than the area of study, as proposed by the Board staff, because it considered it questionable that the entire area was of the same geological environment.

Hudson's Bay contended that the mode of 3,000 acre-feet, even though it is the most likely size to be found in the Zama basin, is not appropriate because it is too small for 83 per cent of the pools in the study and is therefore inequitable when allocating reserves for allowable purposes. In order to allocate a fair reserve to each pool or group of pools in the Provincial proration scheme, Hudson's Bay stated it would be necessary to use the mean pool size if the Board staff proposal were adopted. A mean of 7,900 acre-feet was suggested.

Hudson's Bay was critical of the Board staff's statistical study on some other accounts:

(a) Grouping the data as Hudson's Bay did is a better statistical approach than the Board staff's approach of using ungrouped data.

(b) Data contained in the Board's Annual Reserves Report (OGCB Report 70-18) provides a larger sample than used by the Board staff and should be used. Hudson's Bay provided the results of its study made on the OGCB Report 70-18 data.

(c) Taking common logarithms of the data normalizes them so that well known probability distributions can be used in analysing the results. In the Board staff approach, theoretical curves were used which are difficult to test for statistical appropriateness.

(4) Views of Chevron

Chevron questioned the Board staff's choice of a mode value for establishing the initial reserves in the Zama area. It submitted that the theoretical mode calculated from the best fit lognormal distribution curve was a questionable procedure, particularily when the theoretical mode of 3,050 acre-feet failed to coincide with the peak frequency shown in the results plotted in either of the Board staff's or Chevron's studies. Imperfect lognormal distribution of data was considered to be the reason for this failure. Chevron submitted that only by using the arithmetic average could reserves and hence allowable allocations for the entire area be reasonably correct. This should be equitable for operators both within and outside the area of concern. Only if the assumption was correct that the largest pools in the area had already been drilled could anything less than the arithmetic average be justified. A study of distribution with respect to time had not been presented by the Board staff.

Chevron also expressed concern that approval of the Board staff proposal would make the economics of development in the Zama basin unattractive.

(5) Views of Apache

Apache considered the Board staff proposal would discriminate against operators in areas such as Zama unless similar studies were made and used in other parts of the Province where reservoirs differ in size from 160 acres. It contended also that geological factors may invalidate statistical techniques. Applying the results of the Board staff study to pools in the region proposed would be incorrect because basins northwest of the Zama basin may contain reservoirs of an entirely different size. The reefs may also be filled with hydrocarbons to various depths or the shape of a reservoir may be an important factor in determining the volume of oil or gas in a pool.

Of the pools encountered, Apache contended that the mode value did not give a realistic value of the pool sizes and Apache favored the median as a more reasonable value and simpler to derive.

Apache stated that in its opinion the present method has not been detrimental to conservation. It believed that the operators would reduce production rates if serious water coning occurred.

(6) Views of Sun

Sun agreed with the Board staff proposal to the extent that the policy of assigning initial reserves to Keg River Pools should be changed. However it advocated the use of the mean of 11,000 acre-feet for initial reserve assignments for the Zama basin. This would be equitable and would provide a reasonable share of the Provincial allowable for these pools as a group. Distribution of allowables among the new pools in the Zama area would be resolved when there is adequate pressure-production data for material balance calculations or other information on which to base reserve determinations. A transition period was suggested to implement the new method.

Sun did not believe that its suggestion of using the mean volume would lead to an imbalance in the total reserve assignment to the Zama area after adjustments were made to the pools at a later date.

(7) Views of Others

In cross-examination of the Board staff some companies indirectly expressed the following concerns:

(a) Banff questioned whether the adoption of the staff proposal could continue to result in some pools which were actually smaller than the "statistical average" having too large a reserve assignment.

(b) Canadian Superior questioned whether average porosity and water saturation for certain areas could be used and it and Chevron expressed concern that under the proposal a well containing 300 feet of pay thickness could be assigned the same rock volume as a well containing only 10 feet.

(c) Texaco Canada made some inquiries in regard to equity and also suggested that more frequent reappraisal of oil reserves within the present system may be more desirable than the Board staff's proposal. Further, it raised the question of whether, if the Zama area were to be considered on a different basis that the rest of the Province, a different approach should also be used on such matters as higher floor allowance, integrating of pools and longer allowable periods. The Board staff replied that it did not endorse these approaches.

(d) Both Dome and Texaco Canada anticipated that the incentives to drill wells in the Zama area would be reduced if the Board staff proposal were adopted.

OTHER PROPOSALS

(1) Views of Mobil

Mobil proposed retention of the present method of initial reserves assignment for new Keg River oil pools in the Rainbow-Zama area. This would retain a uniform approach throughout the Province. Reviews of the pools could be made as soon as data, particularly pressure data, were available. Mobil thought there was some merit in the idea that a statistical value might be assigned to a pool "after a reasonable period had been allowed in which to gather data".

(2) Views of Hudson's Bay

Like Mobil, Hudson's Bay recommended retention of the present system for the Rainbow-Zama area. It considered the findings of Decision 68-9 to be still valid. Improvements in volumetric reserve determinations by the use of seismic data and recently developed geological models can provide reasonable estimates fairly soon and incorrect reserve assignments are only in effect for a short time. Reviews could be made as early as four months after commencement of production from a pool. If studies based on production data or seismic data were not available, possibly the mean reserve value from a statistical study could be used.

(3) Views of Apache

Apache recommended continuance of the present method of initial reserves assignment in all areas of the Province. If any changes in policy were adopted, it must be on a province-wide scale to insure equality of treatment. Apache did not think a statistical approach was applicable but if it were used, the median rather than the mode value should be used for reserve determinations.

(4) Views of Chevron

The positions of Hudson's Bay, Apache, Mobil and Texaco Canada were supported by Chevron. It was concerned that approval of the Board staff proposal would set a precedent for the future and did not favor the idea of what appeared to it to be an unnecessary complication in the proration scheme.

If an operator failed to provide a reserve study within a reasonable length of time, Chevron considered the use of the statistical mean value a possibility.

(5) Views of Texaco Canada

Texaco Canada in its questioning appeared to favor the maintenance of uniformity throughout the Province of calculating initial reserves based on 160 acres with reviews required, possibly within six months for each pool.

VIEWS OF THE BOARD

(1) The Board agrees with the Board staff that initial crude oil reserve assignments, particularly in the Zama basin, do cause some equity problems with respect to Provincial proration and distribution among the pools. The concensus of the operators represented at the hearing was that the inequities were short-lived and within acceptable limits since the reserves are reappraised relatively soon. The Board accepts this view.

(2) With respect to the conservation issues raised by the Board staff, the Board agrees that some conservation losses could occur as a result of high initial allowables, but observes that there was very limited evidence presented to confirm this, and accepts the views of industry that any such losses could be controlled through engineering considerations and early reappraisal of reserves.

The Board agrees only in part with the views expressed by Mobil that equity and allowables are not associated with conservation. From both a practical and administrative point of view, it is desirable to have the initial reserve set realistically so that conservation losses are unlikely to occur. Also, a realistic early reserve estimate would not detract from the normal incentives for an operator to make early plans for enhanced recovery, and would reduce the danger of depleting or damaging the reservoir before such plans could be completed.

(3) The Board considers the argument advanced at the hearing that the Board staff proposal would discourage exploration and development of the Rainbow-Zama area to be irrelevant.

(4) Some operators considered the use of statistical studies a possibility if other studies at the time of reappraisal of a pool's reserve failed to provide useful results. The Board

staff concurred in this view. The Board agrees that a statistical value should not be used in substitution for a reserve determination by more explicit methods but for the Zama area considers that a statistical value could be useful where other methods fail. The Board believes a statistical result should be considered as an aid to judgment in conjunction with such other information as might exist.

Respecting the statistical value that might be used for this purpose, most of the operators advocated the use of some other average than the mode as proposed by the Board staff. The Board doubts that any one average is correct for all purposes. For the Zama basin as presently known the Board considers that 5,000 acre-feet, being midway between the mode and the median values, would be a suitable average rock volume.

If future development should result in extensions to the general Zama Keg River development, and similar conditions for geological reef growth and oil accumulation prevail, the Board may extend the area to which this approach would apply.

(5) The Board agrees with the industry representatives and its staff that the statistical results obtained for the Rainbow basin are less definitive than those obtained in the Zama area. If recourse to these results becomes necessary when reappraising reserves, the Board would have regard for their quality.

(6) The Board appreciates the objective of the Board staff proposal to provide a more realistic initial reserve assignment for oil pools in the Rainbow-Zama area. However, it also acknowledges the views of many of the operators represented at the hearing favoring a uniform approach throughout the Province. The Board concludes that there is merit in retaining the policy of using the area of the drilling spacing unit for initial reserves assignment, but that all reasonable means, including the application of relevant statistical findings, should be used to reappraise, as soon as possible, the reserve so assigned.

DECISION

The decision of the Board is to retain the existing policy of assigning an area of one drilling spacing unit in establishing the initial crude oil reserves for discovery and early follow-up oil wells within the entire Rainbow-Zama area. Effective immediately, however, the Board will require the operators of discovery or early follow-up wells in the Rainbow-Zama area to submit in the month following the first six months of production a reappraisal of the reserve based upon all

available data. At the time of reappraisal the Board may utilize statistical information on pool size in accordance with the preceding discussion under Views of the Board.

OIL AND GAS CONSERVATION BOARD

Frank Manyluk

A. F. Manyluk
Deputy Chairman

DATED at Calgary, Alberta
September 8, 1970

OIL AND GAS CONSERVATION BOARD

Decision 70-7
Application No. 5065

INTEGRATED SCHEME FOR ENHANCED RECOVERY IN
ZAMA KEG RIVER A POOL
ZAMA KEG RIVER C POOL
ZAMA KEG RIVER D POOL
ZAMA KEG RIVER E POOL
ZAMA KEG RIVER F POOL
ZAMA KEG RIVER S POOL
ZAMA KEG RIVER U POOL
ZAMA KEG RIVER EE POOL
ZAMA KEG RIVER FF POOL
ZAMA KEG RIVER PP POOL
ZAMA KEG RIVER QQ POOL
ZAMA KEG RIVER VV POOL
ZAMA KEG RIVER XX POOL
ZAMA KEG RIVER AAA POOL
ZAMA KEG RIVER JJJ POOL
ZAMA KEG RIVER OOO POOL
ZAMA KEG RIVER RRR POOL
ZAMA MUSKEG L POOL
ZAMA MUSKEG O POOL
ZAMA MUSKEG EE POOL
VIRGO KEG RIVER G POOL
VIRGO KEG RIVER L POOL
VIRGO KEG RIVER Q POOL
VIRGO KEG RIVER GG POOL
VIRGO MUSKEG D POOL
BY SOLVENT BANK FLOOD, GAS FLOOD AND WATER FLOOD

THE APPLICATION AND HEARING

Hudson's Bay Oil and Gas Company Limited, as operator, made application under section 38 of The Oil and Gas Conservation Act, 1969, for approval of a scheme for enhanced recovery of oil for the above named pools. Hudson's Bay Oil and Gas Company Limited proposed that the pools be sequentially depleted and that gravity controlled, enriched gas miscible displacement would be applied in the pools except for the Zama Keg River C Pool in which a gas flood would be applied. The applicant further proposed that for an interim period, gas flood would be applied to the Zama Keg River U Pool and the Zama Keg River FF Pool and water flood would be applied in the Zama Muskeg L Pool and requested that the gas flood reserves be recognized for the Zama Keg River FF Pool coincident with the date of reactivation of gas injection to this pool.

The applicant also applied under section 34 subsection (2) of The Oil and Gas Conservation Act, 1969 for the fixing of a single aggregate amount of crude oil or condensate that may be produced from the above named pools or any of them regardless of whether all of the pools would be producing pools during the proration period for which the oil allocation is made.

The matter of ultimate reserves for each of the pools was considered at the hearing.

The application was heard on June 2, 3, 4 and 5, 1970, by the Board with G. W. Govier, P. Eng., A. F. Manyluk, P. Eng. and V. Millard sitting.

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Hudson's Bay Oil and Gas Company Limited	J. C. Gateman, P. Eng. J. T. McManus I. M. Wytrychowski T. H. Renner G. L. Cox R. Sedgewick, P. Eng. P. J. Keiran, P. Geoph. D. E. Baldwin W. E. Brigham	Hudson's Bay
Atlantic Richfield Canada Limited	B. B. Wells, P. Eng.	Atlantic Richfield
Banff Oil Ltd.	A. D. Bradshaw, P. Eng.	Banff
Gulf Oil Canada Limited	R. V. Laing J. F. Bechtold	Gulf
Imperial Oil Limited	D. E. Towson, P. Eng. G. Holland G. A. Pinsky	Imperial
Mobil Oil Canada, Ltd.	C.A.Y. Shepard, P. Eng.	Mobil
Texaco Exploration Company	D. A. Nikiforuk, P. Eng. W. B. Braden	Texaco
Board Staff	R. O'Brien, P. Geol. J. A. Bray, P. Eng. M. Jamil, P. Eng. D. G. Pearson, P. Eng.	

PROVISIONS OF ACT

Section 34, subsection (2) of The Oil and Gas Conservation Act, 1969, reads as follows:

"(2) Notwithstanding subsection (1), where two or more pools in a field or area are subject to an integrated scheme approved under section 38, clause (a) after a public hearing, and where the Board is satisfied

(a) that the scheme would result in significant conservation advantages in the field or area and makes a variation by the Board under this subsection desirable,

(b) with an undertaking by the operator to proceed with the integrated scheme, or an alternate approved by the Board which will result in equivalent or greater recoveries, until the recoverable reserves of all of the pools under the scheme are produced, and

(c) that the reserves which will actually be recovered from each of the pools to be produced under the integrated scheme may be estimated with a reliability comparable to that in the case of single pools not produced under such integrated scheme,

it may vary the manner in which the provincial allowable for crude oil, condensate and pentanes plus is allocated among pools and may fix, for the pools subject to the scheme, a single aggregate amount of crude oil or condensate that may be produced from such pools or any of them, regardless of whether all of the pools will be producing pools during the proration period for which the allocation is made."

Section 38, clause (a) of The Oil and Gas Conservation Act, 1969, reads as follows:

"No scheme for

(a) enhanced recovery in any field or pool,

shall be proceeded with unless the Board, by order, has approved the scheme upon such terms and conditions as the Board may prescribe."

DEFINITION OF THE ISSUES INVOLVED

The issues involved in the application are:

Relating to the aggregate allowable applied for under section 34, subsection (2) of The Oil and Gas Conservation Act, 1969,

1. the conservation advantages of the proposed integrated scheme,

2. the undertaking of the operators, and

3. the reliability with which the reserves may be estimated.

Relating to the approval applied for under section 38, of The Oil and Gas Conservation Act, 1969,

4. the suitability of the proposed enhanced recovery operation in each of the pools.

These issues require an appraisal of the description of the reservoir, the oil in place and the recoverable oil by solvent flooding in each of the proposed pools. These matters are dealt with first under the headings of

(a) reservoir description,

(b) oil in place,

(c) solvent bank,

(d) recovery factors,

(e) production schedule,

(f) project monitoring, and

(g) inter-reef communication.

RESERVOIR DESCRIPTION

(1) Reef Model

The main issues pertaining to the reef model are the height of the lower anhydrite on the reef flanks and the lateral extent of the effective reservoir pay in the Zama Member.

Views of Hudson's Bay. Hudson's Bay used seismic data and well information from all Hudson's Bay wells drilled in the Zama Field to prepare a three dimensional reef model. This was necessary, the applicant claimed, because the variability, small size and usual one well penetration of the Virgo-Zama Keg River reefs preclude any direct and reliable determination of the sizes and shapes of the individual reef pools.

The Hudson's Bay model is shown schematically in Figure 1. The company estimated that the thicknesses of the Keg River reef

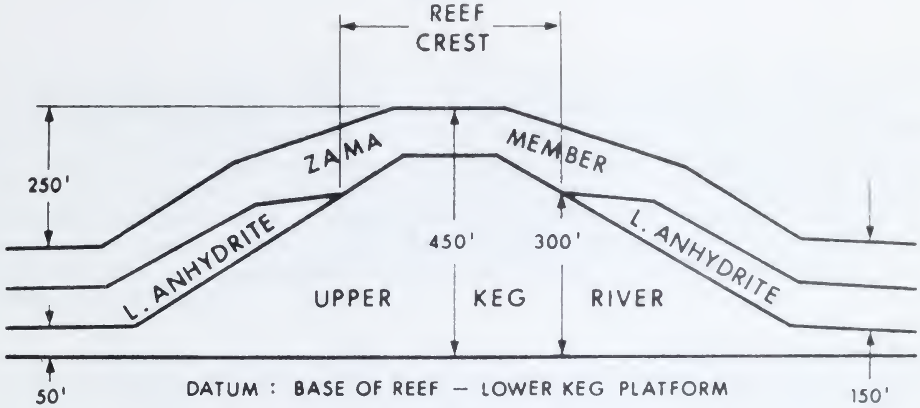

FIGURE 1

HUDSON'S BAY REEF MODEL

(SCHEMATIC)

REPRODUCED FROM HUDSON'S BAY ENGINEERING STUDY
MARCH, 1970

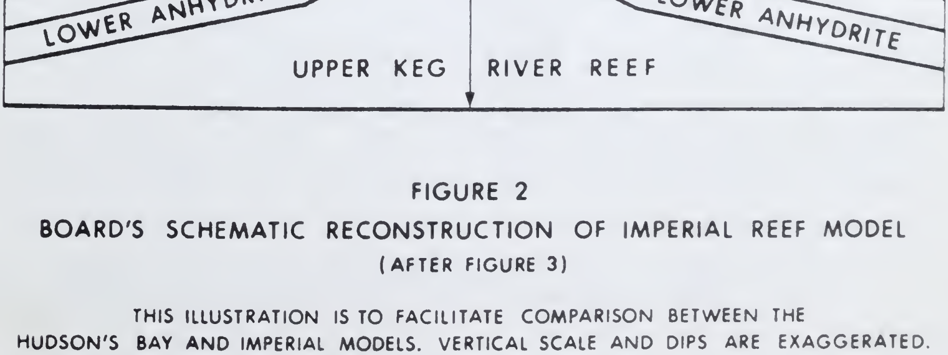

FIGURE 2

BOARD'S SCHEMATIC RECONSTRUCTION OF IMPERIAL REEF MODEL

(AFTER FIGURE 3)

THIS ILLUSTRATION IS TO FACILITATE COMPARISON BETWEEN THE
HUDSON'S BAY AND IMPERIAL MODELS. VERTICAL SCALE AND DIPS ARE EXAGGERATED.

and Zama Member average 370 feet and 80 feet respectively, with the sum of 450 feet representing the total reservoir thickness at the crest. Hudson's Bay interpreted the reefs to be bell shaped with the steepest dips, 20 to 41 degrees, at the flank position and the shallowest dips, less than 10 degrees, at the reef toe and crest. The reefs were determined from seismic data to range from 2,000 to 4,500 feet in diameter at the reef toe. Hudson's Bay maintained that the toe of the reef coincided with the outermost closing isochron for the Slave Point to Red Beds interval.

Hudson's Bay concluded that the lower anhydrite zone flanking the Keg River reefs occurs 300 feet above the Lower Keg River platform. as shown in Figure 1. This conclusion was based on a geological and statistical study in which the heights of the lower anhydrite, as measured at a large number of wells throughout the Zama basin, were plotted. The curve drawn through these points was interpreted to indicate a generalized maximum height for the lower anhydrite of about 300 feet. Hudson's Bay noted that this 300-foot height corresponded with an inflection point deduced to occur on the reef flank on the basis of a probability plot of the Keg River reef thicknesses penetrated at crestal and flank wells. The shape produced by the probability plot was considered to reflect the actual shape of the reef. The probability plot was also used to conclude that the height of the reef crest above the platform varies from 300 to 400 feet.

Hudson's Bay stated that it believes the Zama reservoir to be less effective on the flanks than on the crestal areas. The applicant considered that the effective reservoir limits of the Zama Member occurs where, according to seismic information, a change in the dip of the Zama Member flank takes place. This change in dip is illustrated in Figure 1.

Views of the Interveners. Atlantic Richfield, Banff, Gulf, Mobil and Texaco expressed no views in regard to Hudson's Bay's model, nor did they propose an alternative model.

Imperial Oil had previously submitted its Keg River reef model[1] to the Board and it is shown in Figure 3. To facilitate comparison with Figure 1, this illustration has been re-drawn as Figure 2. This model was developed from 60 wells available to Imperial at the time of the study. The reef profile was determined by plotting the wells in increasing thickness values for the interval, Upper Devonian Island River to Zama Member, with adjustments made for differential warping during this time. The horizontal dimensions were established by using available dip data from the wells and adjusting the wells horizontally until the projected formation tops coincided in adjacent

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(1) Imperial Oil Limited; Proceeding No. 4865 - Annual Reserves Hearing, Virgo Keg River C Pool, January 19, 1970.

wells. Imperial stated that this model compared favourably with its observations of other reefs, present day and ancient, in regard to slope of the flanks, flatness of the crest and overall appearance. Imperial concluded that, regardless of reef height, the top of each reef and the surrounding lower anhydrite occur at essentially the same level. Imperial used its reef model and data from flank wells to determine that the Zama reservoir becomes ineffective about 600 feet from the crest edge. The 600-foot distance was used to estimate the volume of oil in the Zama Member.

Imperial contended that the Hudson's Bay model seriously underestimated the oil volume in the flank Zama which resulted in the calculation of highly optimistic recovery factors.

Views of the Board. The small size and the relatively unknown and variable nature of the Virgo-Zama Keg River reefs, the same general geological setting for the reefs of concern, their usual one well penetration, and the resulting paucity of reservoir data obtainable for an individual reef indicate to the Board that a reef model is a realistic method for determining the reserve estimates and recovery predictions in the area of application. Such a model should be representative of, but not necessarily identical to, any particular reef, but it is desirable that no known data seriously contradict the model. The Board has reviewed the Hudson's Bay and Imperial models in this light to determine if they are relevant to the area of application and if they satisfactorily honour the observed factual data.

The models derived by Hudson's Bay and Imperial differ from each other in the following respects: the height of the lower anhydrite relative to the reefs, the distance that the effective reservoir in the Zama Member extends beyond the crestal area and the flank slopes of both the reef and the Zama Member. These differences may be noted by comparing Figure 1 with Figures 2 and 3.

Concerning the height of the lower anhydrite relative to the reefs, the Board believes that the Hudson's Bay model may not accurately accommodate some of the data available for wells in or near the area of application. At nine such wells that penetrated the high flank portions of the reefs, the Board has concluded that the lower anhydrite occurs near the top or flat part of the reefs, even though the nine reefs range in thickness from 300 to 400 feet. The Board also believes that the thickness of the reefs is directly associated with the Lower Keg River structure that was in effect when the reefs were growing and that the reefs all grew to approximately the same level. It is the Board's opinion that these circumstances could be a reason for the lower anhydrite being observed near the top of the reefs in each of the nine cases. Due to the nature of the data analysed, however, the distance below the flat part of the reef to the lower anhydrite cannot be determined with precision and an uncertainty of about 20 feet exists in this distance. Having regard to this lack of precision, the Board's best generalization is that, for the typical pool, the lower anhydrite occurs some 20 feet below the flat top of the reef, as illustrated in Figure 4.

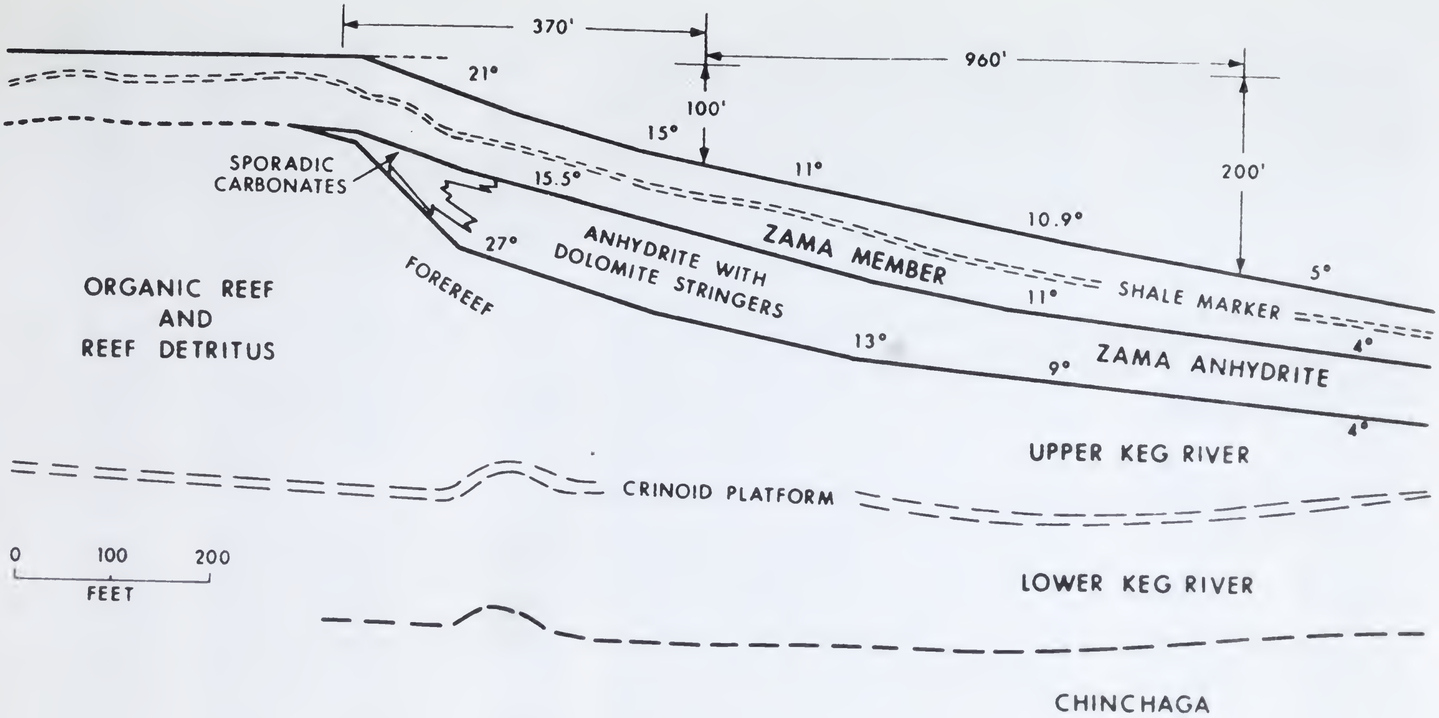

FIGURE 3

IMPERIAL REEF MODEL

AFTER FIGURE 2 OF PROCEEDING NO. 4865, ANNUAL RESERVES HEARING, VIRGO KEG RIVER C POOL, JANUARY 19, 1970

OIL AND GAS CONSERVATION BOARD
ALBERTA NOVEMBER 1970

One exception to this generalization has, however, been noted. The reef at the Zama Keg River JJJ Pool appears to be some 40 to 60 feet higher than the nearby reefs, and the Board thus concluded that the lower anhydrite in this instance may be a comparable interval of some 60 feet below the top of the reef.

A comparison between Figures 2, 3 and 4 indicates that there is general agreement between Imperial and the Board on the foregoing issue, as the Imperial study suggests that the dense anhydrite may occur somewhat below the flat part of the reef.

The lateral extent of the effective reservoir conditions in the Zama Member is the second issue of concern to the Board. In view of the limitations of seismic information and the lack of direct evidence for relating changes in the Zama slope to the lateral termination of effective reservoir conditions, the Board does not accept Hudson's Bay's method for determining the limits of the Zama reservoir. Nor is the Board prepared to accept the Imperial model as a basis for concluding, as does Imperial, that the porosity in the Zama Member extends 600 feet from the reef crest. As the Board is not prepared to fully accept these aspects of the Hudson's Bay and Imperial models, it considered available data from whipstocked wells , and dual well reefs to reach the conclusion that 400 feet is a reasonable distance to expect effective Zama reservoir conditions to extend from the edge of the crestal area. These data also indicated that the Zama thickness and porosity deteriorate in the off-reef areas in an unpredictable manner. For calculation purposes, the Board considers that the 400-foot tapered extension is approximately equivalent to a lateral extension of the well-bore thickness and porosity of the Zama Member for a distance of about 200 feet from the crest.

Although the different models display somewhat different dips on the reef and Zama flanks, they have no significant bearing on recovery predictions.

(2) Porosity

Views of Hudson's Bay. To obtain the most realistic reservoir parameters for each pool, Hudson's Bay proposed a lithological facies model based on the examination and analysis of 3,764 feet of Zama and Keg River core from 35 Hudson's Bay-operated pools. Logs which had been correlated to core data were used to infill the uncored intervals. Nine facies groups with their characteristic porosity, connate water saturation and permeability were recognized for limestone and dolomite, respectively.

The reef structure model was divided into eight fifty-foot thick horizontal slices and the Zama Member into two fifty-foot slices. Facies maps were prepared for each layer and planimetered to obtain

the volume of each facies. By multiplying the facies volumes in each layer above the pool oil-water contacts by the appropriate facies porosity and averaging the total, a porosity was determined for each pool.

Hudson's Bay stated that the porosity so determined was more realistic for a pool than the well bore porosity. A radial variation in porosity was evident in the reefs and, as individual well bores would sample this variation randomly, a composite porosity average would better represent a given reef.

Views of the Board. The Board agrees with the applicant that a lithological facies model provides a more realistic porosity for the pools than would the individual well bore logs and core. Therefore, the pool porosities determined by Hudson's Bay are adopted for the respective pools.

(3) Connate Water Saturation

Views of Hudson's Bay. Hudson's Bay used the analysis data of its oil-base core from the well HB Zama N 13-23KR-116-6, to determine water saturation-porosity relationships for limestone and dolomite. The proposed relationships, which were obtained by the technique of least squares curve fitting of the core data, were:

$$\text{Limestone} \qquad Sw = \frac{1910}{\phi^{2.245}}$$

$$\text{Dolomite} \qquad Sw = \frac{55.89}{\phi^{0.904}}$$

The porosity of each lithofacies was applied to these expressions to calculate the volumetrically weighted average connate water saturation. In the oil-water transition zones, the log resistivity was used to determine water saturation after a correlation had been established between resistivity and the oil-base core for the 13-23KR well. The two values obtained, one from the model for the oil zone and the other from the resistivity log for the transition zone, were combined to establish the overall water saturation for each pool.

Hudson's Bay believed that the one oil-base core contained a good representation of the different rock types and various lithofacies. The company's opinion was that the oil-base core data was more reliable than log or capillary pressure data for determining water saturation.

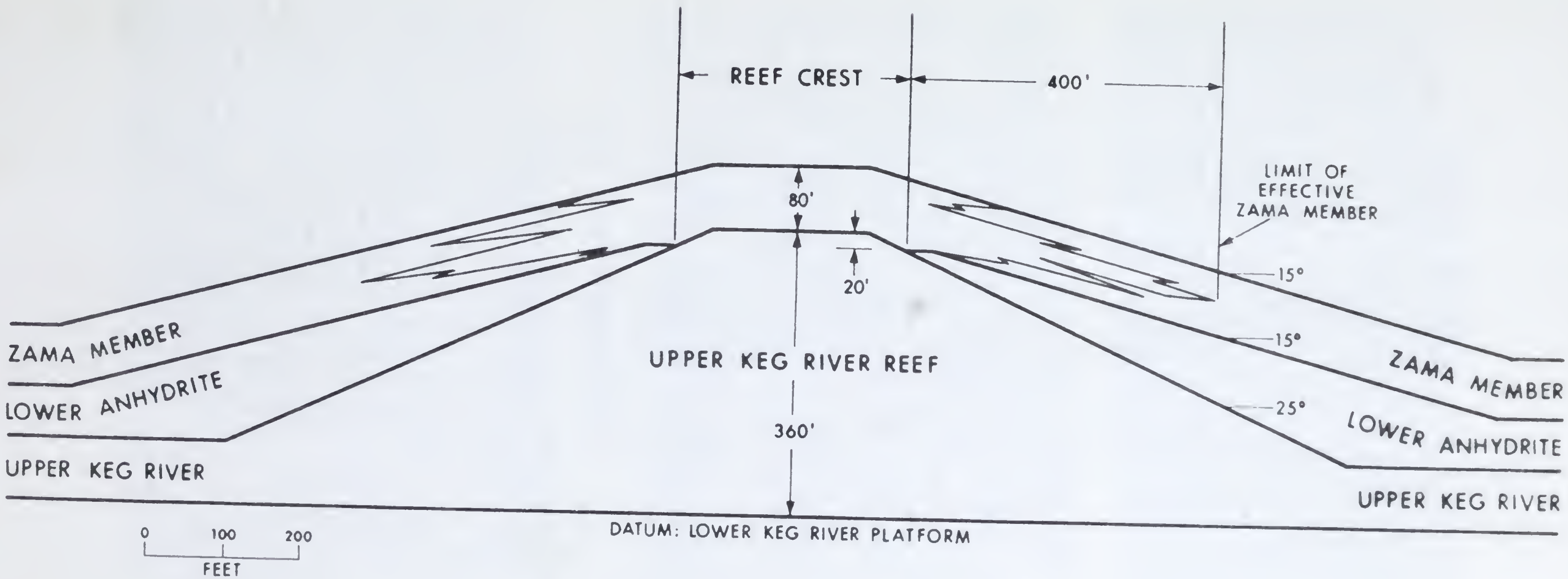

FIGURE 4

BOARD MODEL OF TYPICAL REEF

(SCHEMATIC)

Views of the Board. The Board agrees with Hudson's Bay that oil base core data will provide the best means for determining the connate water saturation for pools in the proposed scheme. The Board notes that two oil base cores (HB Zama N 13-23KR-116-6 and Chevron SOBC Zama 2-9-117-5) were obtained from the Zama-Virgo area and is of the opinion that data from both these oil base cores should be considered when establishing a connate water saturation correlation. The Board notes that the data from the oil base cores from the two wells are in general agreement but that the data from HB Zama N 13-23KR-116-6 gave low connate water saturations in the region of the composite porosity of 7.2 per cent for both the limestone and dolomite lithologies. Using the data from the two oil base cores, the Board established separate connate water saturation-porosity relationships for the limestone and dolomite lithologies.

The Board noted that a significant transition zone occurs between the oil and water zones and that the thickness of the transition zone was different for each lithology. The Board determined a 14-foot transition zone having the connate water saturation of 37 per cent for the dolomite lithology and a 33-foot transition zone having a connate water saturation of 46 per cent for the limestone lithology. The Board was unable to weight the connate water saturation volumetrically according to lithology for each pool similar to Hudson's Bay's procedure. Accordingly, the average connate water saturation for each pool was determined by footage weighting the connate water saturation obtained for (1) the Zama member using the dolomite relationship, (2) the Keg River reef using the relationship of the predominant lithology present in the reef, and (3) the transition zone having regard for its lithology. The average porosity determined by Hudson's Bay was used for each pool. The connate water saturation obtained in this manner was adjusted upward by one percentage point to account for the flushing of the water during the oil-base coring operations.

(4) Pore Compressibility

Views of Hudson's Bay. Hudson's Bay reported its results of the pore compressibility measurements made using the hydraulic loading technique on four cores from the Zama area. The laboratory measurements yielded results that were in general agreement with Van der Knapp's correlations for the limestone but were larger than Van der Knapp's correlations for the dolomite. Hudson's Bay submitted that it accepted Geertsma's theory, as it applies to the Zama-Virgo area, that the actual boundary conditions present in the reservoir were of constant vertical pressure with the absence of bulk deformation in the other directions of stress and thus the pore compressibility measured by the hydraulic loading technique was about double the in situ compressibility. Hudson's Bay therefore concluded from its studies that a pore compressibility factor of 3.0×10^{-6} 1/psi is appropriate to use in all undersaturated material balance calculations. Hudson's Bay stated that if the pool compressibility factor from the hydraulic loading technique was used directly, the oil in place determined by the material balance would be reduced by some 10 per cent.

Views of the Board. The Board agrees with Hudson's Bay's contention that the pore compressibility measured in the laboratory by the hydraulic loading technique is higher than the in situ compressibility. The Board therefore adopted in its material balance calculations the compressibility factor of 3.0×10^{-6} 1/psi proposed by Hudson's Bay.

OIL IN PLACE

Views of Hudson's Bay. Hudson's Bay calculated the oil in place for each pool using both the material balance and volumetric techniques. It submitted one or more of the following material balance calculations in support of the oil in place for each of the various pools:

(1) Undersaturated and saturated material balance calculations neglecting water influx were submitted to support oil in place where water influx was considered negligible.

(2) The geometric-ratio iterative procedure (GRIP method) which combines aspects of both material balance and volumetric calculations by assuming a water to oil zone ratio was utilized where reservoir flow was considered to approach steady state.

(3) The steady-state aquifer expansion method was utilized where the aquifer was considered to extend to the last closing contour of the upper Keg River structure.

(4) The unsteady-state water influx method was used by the applicant for those pools which were in early stages of depletion and where knowledge of the aquifer effects was limited.

The oil in place value assigned to each reservoir by Hudson's Bay was selected after careful consideration of the validity of each calculation. The depth versus area and the depth versus cumulative hydrocarbon pore volume curves constructed from the geophysical-geological model were then adjusted where necessary to agree with the selected oil in place.

Views of the Board. The Board calculated the oil in place for each pool using both the volumetric and material balance calculation techniques. For the volumetric estimate the Board determined the crestal area from seismic information having regard for the largest isochron values recorded from the seismic data. Assuming an equivalent circular area, the rock volume of the pool was determined by employing the Board's previously described model. The oil in place was then calculated utilizing the individual pool porosity estimated by Hudson's Bay, connate water saturation as described previously and hydrocarbon fluid properties for each pool.

Undersaturated or saturated material balance calculations were made on all the pools, assuming the same reservoir configuration as in the volumetric calculations. The oil-water contact in the Zama member was assumed to be at the same level as in the Keg River reef. The Board believes its material balance approach closely approximates the GRIP method utilized by Hudson's Bay and believes this approach to give reliable results. The Board found the unsteady-state water influx method useful in arriving at an oil-in-place in a few selected instances where the other material balance approaches gave an excessive range of results which could not be supported by volumetric evidence.

Table 1 compares the reservoir parameters and oil in place values as submitted by Hudson's Bay and set by the Board.

SOLVENT BANK

(1) Solvent-Oil Miscibility

Views of Hudson's Bay. The proposed solvent is a multi-component system consisting of nitrogen, carbon dioxide, hydrogen sulphide, methane and ethane plus. Hudson's Bay stated that its experiments suggest that when the solvent contains acid gases, hydrogen sulphide enriched the solvent approximately like ethane plus. (The phrase "ethane plus" used hereafter means both ethane plus and hydrogen sulphide.)

Hudson's Bay stated that an empirical correlation such as Benham's(2) is useful to estimate the solvent-oil miscibility. A comparison of the results of the solvent-oil miscibility test made by Banff Oil Ltd. on the Rainbow Keg River B Pool crude oil whose properties are representative of the other Hudson's Bay pools suggested to Hudson's Bay that a solvent bank designed to be miscible with the crude oil using Benham's correlations contains an ethane plus concentration of about 6 mol percentage points higher than that determined experimentally.

Hudson's Bay conducted a series of laboratory tests at pressures of 2000 psig, 2485 psig and 2985 psig and a temperature of 157°F, 170°F and 173°F, using reservoir fluid samples from the Zama Keg River EE, Zama Keg River FF and Zama Keg River VV Pools and various solvent compositions with hydrogen sulphide concentration varying from 0 to 42.3 mol per cent. The tests indicated that hydrogen sulphide behaved like ethane and that solvent composition required to achieve miscibility could be predicted using Benham's correlations if the hydrogen sulphide was treated as a pseudo-hydrocarbon of molecular

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(2) Benham, A. L., Dowden, W. E., and Kunzman, W. J.: "Miscible Fluid Displacement - Prediction of Miscibility", Trans. AIME(1960) Vol. 219, 229.

weight of 28 instead of 34. Hudson's Bay stated that the aforementioned tests also confirmed that Benham's correlations provide a safety factor of 6 mol per cent ethane plus for the proposed solvent.

Hudson's Bay contended that when interpreting the results of the solvent-oil miscibility test the absolute level of recovery at breakthrough of the displacing solvent is not in itself the criterion to be used in deciding whether the displacement was miscible. The shape of the recovery curve and the amount of recovery having regard for the test conditions are important in deciding on whether miscibility was achieved in the test.

Hudson's Bay divided the pools in the proposed scheme into four groups as shown in Figure 5 having regard for geographical location to reduce pipe line cost, crude type, reserves and productivity. Hudson's Bay proposed that the solvent bank for the Group 1 pools would contain 61.9 mol per cent ethane plus which includes 36.8 mol per cent hydrogen sulphide. It also indicated that the quantity of hydrogen sulphide could be as high as 45 mol per cent. Hudson's Bay stated, however, that after the gas plant is in operation, if the actual gas plant products varied appreciably from the range considered in its studies, then additional laboratory tests would be conducted to establish the conditions for miscibility using the actual plant product composition.

The solvent composition for the Groups 2, 3 and 4 pools was also estimated from Benham's correlations using the composition of the crude oil in each group which required the highest ethane plus concentration in the solvent to be miscible with the reservoir fluid.

Views of Texaco. Texaco contended that none of the slim tube displacement tests conducted by Hudson's Bay exhibited solvent-oil miscibility as "the data does not result in a characteristic breakover point at high recovery". It expressed the opinion that, even under partial miscibility conditions, recovery of most of the oil in place in the slim tube could be achieved provided the two phase flow in the mixed zone is followed by a single phase flow. Texaco further stated that it is the abrupt change of the slope of the oil recovery at solvent breakthrough versus ethane plus curve which defines the solvent-oil miscibility conditions.

Views of the Board. The Board accepts Hudson's Bay's contention that, in describing the solvent composition, the carbon dioxide content can be considered as part of the methane fraction and the hydrogen sulphide content can be considered as part of the ethane plus fraction.

The Board agrees with Hudson's Bay that the shape of the miscible displacement curve, the final recovery obtained from the tests, and the test conditions are important when determining whether the displacement test was miscible. It does not agree with Texaco that the "breakover point" is the only basis for determining whether the

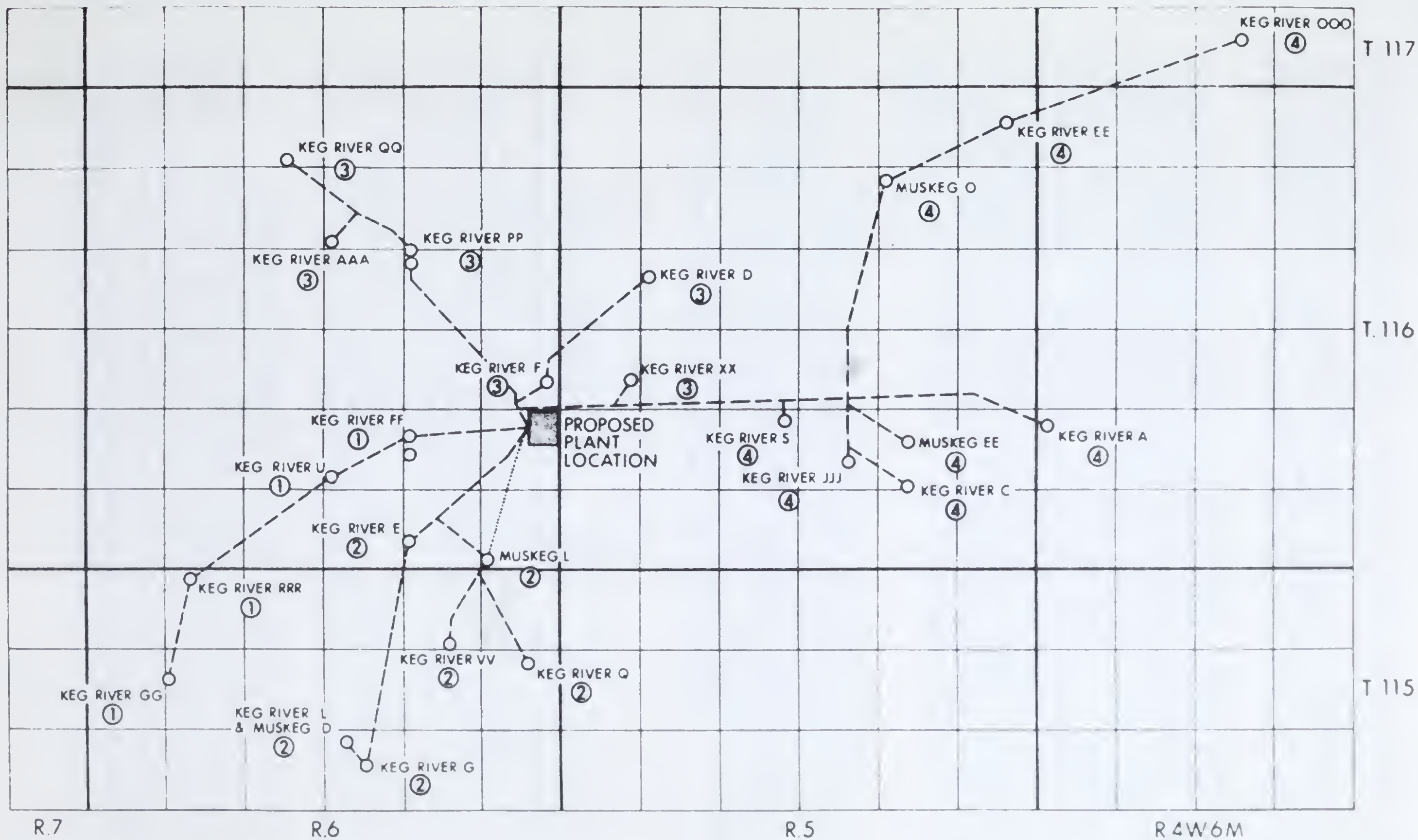

FIGURE 5

PHASE GROUPING

REPRODUCED FROM HUDSON'S BAY SUBMISSION

test exhibited miscibility. Based on these criteria the Board is of the opinion that there is some doubt that displacement tests No. 2, 3, 3a and 4 (Exhibit 3) satisfactorily define miscibility conditions for the solvent-oil system. The Board, however, is prepared to accept tests No. 1 and 5 as satisfactorily defining miscibility conditions.

The Board believes that a solvent composition designed using Benham correlations appears to provide some safety factor for a given solvent composition when compared with the experimental results. However, the Board does not agree with Hudson's Bay that the safety factor of 6 mol per cent ethane plus indicated for the Rainbow Keg River B Pool reservoir fluid would also apply to the pools in the proposed scheme. An interpretation of the displacement tests No. 1 and 5 suggests a safety factor of about two mol per cent ethane plus. The Board believes that the solvent bank should be designed with a minimum safety factor of 3 to 5 percentage points ethane plus when the reservoir pressure has been increased to 2000 pounds per square inch gauge and where the solvent is just miscible with both the crude oil and the driving gas.

Subject to further testing, the Board believes that for the interim the solvent composition for the Group 1 pools should contain 36 mol per cent methane, carbon dioxide and nitrogen and 64 mol per cent ethane plus with the hydrogen sulphide content not more than 37 mol per cent but believes that before the final solvent composition is specified for each group, further tests should be conducted using actual plant products and actual reservoir fluids.

(2) Solvent-Gas Miscibility

Views of Hudson's Bay. Hudson's Bay determined the phase behaviour in the laboratory for a system of varying solvent composition at temperatures of 150°F and 173°F. These temperatures cover the range of temperature variation in the proposed scheme. The tests were conducted on liquid streams expected from the gas plant, with an enriched stream containing approximately 54.34 mol per cent hydrogen sulphide. Its studies showed that if the pressure is greater than 1330 psig, all solvents produced will be in a single phase at reservoir temperatures of 150°F and 173°F. Hudson's Bay stated that under these circumstances and the proposed operating pressures for the pools there would always be complete miscibility at the solvent-gas interface.

Views of the Board. The Board agrees with Hudson's Bay that under the conditions of the laboratory test, solvent-gas miscibility will be assured if the reservoir pressure is not less than 1330 psig. However, if the gas plant liquid stream used to make up the solvent is significantly different than that used in the laboratory test, it is possible that the minimum pressure required to ensure miscibility will be higher. The Board believes that the solvent-gas miscibility should be confirmed using actual plant products.

(3) Bank Size

Views of Hudson's Bay. Hudson's Bay determined a molecular diffusion coefficient for the solvent-gas system by theoretical calculations which consider both the solvent and gas fluids in gaseous form. The diffusion coefficient corrected for reservoir pressure was calculated to be 9.5×10^{-2} ft^2/day (102.2×10^{-5} cm^2/sec). The molecular diffusion coefficient between the proposed solvent and oil was also determined from theoretical calculations. Hudson's Bay adopted a molecular diffusion coefficient of 1.78×10^{-2} ft^2/day (19.14×10^{-5} cm^2/sec) in its solvent bank calculations.

Hudson's Bay estimated the rock tortuosity factor necessary in estimating the effective molecular diffusion in the reservoir rock from the correlation of the formation resistivity factor and porosity it developed from the Zama-Virgo field samples. The formation resistivity was developed at the overburden pressure that exists in the reservoir.

Hudson's Bay conducted four miscible displacement tests to determine the mixing coefficient (σdp) in the estimation of the dispersion coefficient using an octane-dodecane fluid system and two reservoir core samples. In analysing laboratory miscible displacement tests it stated that the concentration profile should be adjusted to account for experimental measurement errors. It also emphasized the importance of incorporating the proper boundary conditions into the solution of the general dispersion equation. In this connection it stated that the solution to either the simple or the capacitance dispersion equation (Coats and Smith[3]) for the infinite case could be applied to the finite case provided certain adjustments are made.

Hudson's Bay stated that the mixing zone length was calculated assuming the simple dispersion equation (no capacitance) using a mixing zone length formula, established by it for a conical system, and based on a 10-90 per cent concentration limit. The proposed formula accounts for the dispersion of the solvent bank by molecular diffusion and convective mixing. In reply to a question by Texaco, Hudson's Bay stated that a solvent bank designed using the 10-90 per cent concentration limit would be miscible at the end of the scheme life because, although the solvent is diluted with gas and enriched with oil, the resulting solvent concentration does not reach a level where miscibility is lost.

Hudson's Bay expressed the opinion that capacitance effects are important and should be incorporated in the solvent bank design. It concluded that the capacitance effect observed from the laboratory

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(3) Coats, K. H. and Smith, B. D.: "Dead-End Pore Volume and Dispersion in Porous Media", Trans. AIME (1964) Vol. 231, 73.

tests and applied to the field conditions resulted in a pseudo-mixing coefficient (σdp) of 3.4 cm as compared to 2.5 cm when neglecting capacitance effects. This resulted in an increase in the total mixing zone length of 4 per cent over that predicted neglecting the capacitance effects.

Hudson's Bay studied the interrelationship between solvent bank size, solvent coning and recovery and calculated that the highest ultimate recovery would be accomplished by deliberately producing the wells under controlled solvent coning conditions. It used a three dimensional mathematical simulator and solvent bank sizes of about 8, 10, 12 and 14 per cent of hydrocarbon pore volume to investigate the effect of varying production rates on solvent and gas coning. It stated that the results showed a solvent and gas cone would develop in the early life of the scheme. Solvent coning could be minimized by reducing the production rate but this would extend the total depletion time for the pools which in turn would result in the need for a larger solvent bank for each of the pools in the scheme. Hudson's Bay stated that to maximize recovery using the available solvent it would be necessary to produce solvent through coning. The produced solvent would be regenerated and used for injection to the other pools. Hudson's Bay stated that "at a solvent bank size of about 13 per cent of the oil-in-place, the incremental gain in recovery becomes less than the incremental increase in bank size" and therefore proposed a 13 per cent solvent bank for the pools in the proposed scheme.

Hudson's Bay calculated the critical rate for stable bank displacement for each pool using (1) pore volume weighted mean vertical permeability, (2) its composite geological model, and (3) its critical rate equation (Exhibit 3, Appendix F). It stated that the forecast production rates are considerably less than the rate evaluated using the critical rates.

In discussing the safety factor, Hudson's Bay stated that a 13 per cent solvent bank is sufficient to offset any adverse effect caused by sections of low permeability, mixing in the transverse direction due to solvent coning and other unknown factors. The proposed solvent bank size, in Hudson's Bay's opinion, would contain a safety factor of about 14 per cent.

<u>Views of Texaco</u>. With regard to the views of Hudson's Bay concerning experimental measurement errors and boundary conditions, Texaco stated that the capacitance equation of Coats and Smith is free of any material balance errors but when applied to the analysis of the laboratory data on finite core samples, appropriate adjustments should be made to the effluent measurements to account for the boundary conditions.

Texaco stated that if the solvent bank size was designed to be initially just miscible with the reservoir fluid using the 10-90 per cent concentration limit method, then, in its opinion, the

displacement would become immiscible before the end of the pool life. Texaco contended that complete miscibility between the solvent-oil and solvent-gas systems can be assured if the solvent bank is designed using the pseudo three-component system (ternary diagram).

Views of the Board. The Board calculated a solvent-gas molecular diffusion coefficient of 123 x 10^{-5} cm^2/sec by the method of Hirschfelder(5) using a binary system and further adjusted for a multicomponent system using the method of Wilke and Chang(6) as compared to a solvent-gas molecular diffusion coefficient of 102.2 x 10^{-5} cm^2/sec as proposed by Hudson's Bay. A solvent-oil molecular diffusion coefficient of 9 x 10^{-5} cm^2/sec was calculated by the Board using the Hill and Lacey(7) correlations for a methane-oil system. The solvent-oil diffusion coefficient calculated by Hudson's Bay was 19.14 x 10^{-5} cm^2/sec. The Board believes that the theoretical calculations provide high values when compared to actual data for similar systems. The Board notes that there is a lack of experimental data and also a lack of reliable theoretical methods for predicting solvent-gas and solvent-oil molecular diffusion coefficients. It further notes that the solvent bank size is not highly sensitive to a moderate change in the molecular diffusion coefficient since the mixed zone length is proportional to the square root of the dispersion coefficient which includes the molecular diffusion coefficient. The Board, therefore, adopted a solvent-gas molecular diffusion coefficient of 102 x 10^{-5} cm^2/sec and a solvent-oil molecular diffusion coefficient of 9 x 10^{-5} cm^2/sec.

The Board agrees with Hudson's Bay's correlation of formation resistivity and porosity for the pools in the proposed scheme.

The Board agrees with Hudson's Bay and Texaco that the effect of the boundary conditions should be properly accounted for in interpreting the results of miscible displacement tests on small core samples. It also agrees with Hudson's Bay's manner of accounting for the effect of these boundary conditions by applying an adjustment factor to the solution of the general dispersion equation which includes the capacitance parameters. It further agrees with Hudson's Bay that if some material balance errors caused by inaccurate measurement are inherent in the miscible displacement test, appropriate adjustment should also be made to the effluent concentration profile before it is analysed for the mixing parameters.

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(5) Hirschfelder, J. C., Curtis, C. F., Bird, R. B., "Molecular Theory of Gases and Liquids", Wiley, N.Y. (1954).

(6) Wilke, C. R., Pin Chang, "Correlation of Diffusion Coefficients in Dilute Gases," Am. Inst. Chem. Eng. J.4 (1958) 137.

(7) Hill, E. S., Lacey, W. N., "Rate of Solution of Methane in Quiescent Liquid Hydrocarbon II", Ind. Eng. Chem. 26(12)(1934)1324.

The Board agrees with Texaco that if a solvent bank size is designed using a 10-90 per cent concentration limit method and if the solvent is just miscible with the reservoir fluid, it will lose miscibility with the reservoir fluid before the end of the pool life. It further agrees with Texaco that the solvent bank size should be designed using the ternary diagram method and the general dispersion equation allowing for the capacitance effect.

The Board believes that when determining the final solvent bank size both water and solvent coning should be considered in calculating the time required for the depletion of a pool. While Hudson's Bay assumed that water coning would not be a problem, the Board believes that, on the basis of its two dimensional mathematical model study and Hudson's Bay's proposed production schedule, water coning would be a significant factor. To minimize coning the production rates would have to be reduced substantially which would have the effect of increasing the scheme life. For the purpose of the bank size calculation, the Board estimated a maximum life of 30 to 35 years having regard for forecast allowables, the critical rate effect, and production restrictions that would likely be required to prevent premature water coning.

The Board made an independent estimate of the effect of capacitance on the mixing zone length using the Coats and Smith equation adjusted in the manner proposed by Hudson's Bay. The capacitance parameters used in the calculations for the solvent-oil and solvent-gas system for the field case were estimated from the parameters determined from the laboratory data using an octane-dodecane fluid system and other experimental data using actual fluid systems as reported in Application No. 4404[8].

Using the capacitance equation, the production schedule developed by the Board to minimize coning and the pseudo three-component system, the mixed zone length was calculated for each pool as the solvent bank moved through the reservoir. A safety factor was applied to account for unknowns in the solvent bank size calculations. The solvent bank was then adjusted to account for solvent which would be coned during the displacement.

The Board has not made an independent study of the interrelationship of the amount of solvent coning, oil recovery and bank size and is prepared to accept Hudson's Bay's analysis of the volume of solvent which would be produced, through coning, during the life of the pool. It believes that the solvent and gas which would be coned at the proposed production rates would contribute to some mixing.

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(8) An application for approval of an enhanced recovery scheme by solvent flooding of the Wizard Lake D-3A Pool by Texaco Exploration Limited. Board Decision 69-8.

It also believes that there are uncertainties involved in defining the vertical and horizontal permeability in the proposed pools and therefore an appropriate safety factor should be applied to account for the extra mixing due to solvent fingering into the oil zone. To account for extra mixing from solvent fingering, solvent and gas coning and other unknown factors, the Board believes that an overall safety factor of 20 per cent should be applied to that part of the solvent bank excluding the volume coned. The Board's interpretation of Hudson's Bay's application is that when the effect of capacitance is accounted for the proposed solvent bank size incorporates a safety factor of about 11 per cent.

The Board estimated a total solvent bank size of 19 per cent of the hydrocarbon pore volume as compared to 13 per cent as proposed by Hudson's Bay. The 6 percentage point difference is a result of differences in judgement, primarily with respect to

(1) the use of ternary diagram instead of 10-90 per cent concentration limit method,

(2) the estimated maximum scheme life,

(3) the variation in the reservoir configuration from the average pool,

(4) the effect of capacitance, and

(5) the safety factor.

In view of these differences the Board believes that a value intermediate between the Board and the applicant would be appropriate. The Board therefore has adopted a solvent bank size of 16 per cent of hydrocarbon pore volume for all pools to be solvent flooded in the proposed scheme. Table 3 shows the Board's final solvent bank size for each pool of the proposed scheme.

(4) Placement

Views of Hudson's Bay. Hudson's Bay used a three dimensional mathematical simulator to study the placement of the proposed solvent bank using its Virgo-Zama composite model as the basis for pool shape and rock properties. Hudson's Bay presented the results of studies using five different cases to show the effect of the varying injection rates, the presence of a gas cap and the positioning of the injection well on the bank placement based on about 8 per cent solvent bank. It concluded that a single centrally located solvent injector would be adequate to provide a horizontal solvent bank in all the pools. Where a well is located on the flank, the study showed that the solvent would "spread evenly throughout the reservoir indicating good coverage", but that early solvent coning would occur as a result of the

poor reef properties at the edge of the pool. To minimize the coning effect, Hudson's Bay stated that an additional well would be drilled on the crest of the pools where the original well was drilled on the flank. For pools with a gas cap, the injection well would be completed so that the solvent would be injected at the top of the gas cap. This would result in displacing some of the residual oil from the gas cap and would provide complete solvent coverage at the gas-oil contact.

Hudson's Bay stated that in all of its simulator runs the solvent was injected at a rate of 500 barrels per day for a nominal bank size of 8 per cent of the reservoir hydrocarbon pore volume. The three dimensional reservoir simulator study indicated that good reservoir coverage of the solvent bank will be achieved at the end of two years from the start of solvent bank placement.

Views of the Board. The Board has considered the mathematical and computer techniques used by Hudson's Bay in the bank placement study, and is in general agreement with Hudson's Bay's assessments of solvent bank placement for the pools where the well is located on the crestal area. The Board further agrees with Hudson's Bay that where the only well is located on the flank of the pool an additional well should be drilled on the reef crest.

RECOVERY FACTORS

Views of Hudson's Bay.

Primary Depletion. Hudson's Bay calculated a primary depletion recovery of 52 per cent for its composite reservoir model using one and three dimensional simulators. Individual pool recovery factors were calculated by adjusting the composite model recovery factor to account for each pool's reservoir configuration and rock and fluid properties. Hudson's Bay adopted a residual oil saturation of 36.5 per cent of the hydrocarbon pore volume (32.5 per cent pore volume) for the region of the reservoir above 138 feet above the oil-water contact in each pool. The residual oil saturation for the remaining part of the reservoir was obtained from the three dimensional reservoir simulator results. Hudson's Bay expressed the opinion that the low producing rates near the end of the producing life of the reservoir would result in minimal water coning and thus did not consider the effect of water coning in the recovery calculation. It concluded from its simulator results that, because of gas coning, very little oil would be recovered from below the top producing perforation or in the bottom 17.5 feet of the reservoir. The individual pool recoveries were determined by adjusting the composite model recovery to account for losses resulting from

(a) the static cone above the lower anhydrite spill point which is dependent on the inner and outer radius at that elevation,

(b) the unrecoverable oil in the region of the "wing" of the reservoir that is below the spill point,

(c) the variation in rock quality, and

(d) the variation in viscosity.

The individual pool primary recovery factors are shown in Table 3.

Gas Flood. Hudson's Bay used the same approach to determine gas flood recovery factors as was used to determine the primary recovery factors. The ultimate gas flood recovery factor of 57.6 per cent resulted from the calculation performed by the simulators. The residual oil saturation of 32.5 per cent of pore volume was applied to the region of the reservoir above 94.9 feet above the oil-water contact. Losses due to a static cone above the spill point and unrecoverable oil in the "Zama wing" were identical to that for the primary case. Adjustments were also made to account for the variation in viscosity and rock quality from Hudson's Bay's composite model. The recovery factors for the pools proposed to be gas flooded are shown in Table 3.

Water Flood. Hudson's Bay proposed to water flood only the Zama Muskeg L Pool. An ultimate water flood recovery factor of 54 per cent was calculated using the one and three dimensional simulators. Adjustments were made to this recovery factor in a manner similar to that used in the primary and gas flood recovery mechanisms. The remaining oil at abandonment was calculated from the saturation profile. The volumes of oil in the reef above the point of well penetration was assumed to be unrecoverable. An ultimate water flood recovery factor of 42 per cent resulted from the calculations for the Zama Muskeg L Pool.

Solvent Flood. Hudson's Bay calculated miscible displacement recovery factors based on the results of a three dimensional miscible simulator for the five different reservoir configurations that represented the range of reef sizes and geometry encountered in the proposed scheme. The base case was simulated with a solvent bank size of about 8 per cent and the results were adjusted to reflect assumed solvent bank sizes of 10, 12 and 14 per cent to determine a relationship between recovery and bank size. Hudson's Bay assumed a residual oil saturation of two per cent hydrocarbon pore volume in the miscibly swept zone. The oil that would be recovered by an immiscible gas displacement after miscibility was lost was added to the cumulative production determined from the results of the miscible displacement simulator calculations to obtain the ultimate recovery factor.

Hudson's Bay concluded from its study that the incremental gain of solvent flood over primary depletion for an optimum bank size of 13 per cent was 34 to 36 per cent of the oil in place. Considering oil recovery during blow-down it was concluded that incremental recovery would be 36 per cent.

To determine the individual pool solvent flood recovery factors the applicant added an incremental 36 percentage points to the primary recovery of the "movable oil" defined as the original oil in place less the oil in the "Zama wing" below the lower anhydrite spill point. A further adjustment was made to account for the losses occurring in the secondary gas cap.

Views of Imperial. Imperial submitted that the Hudson's Bay reef geometry seriously underestimated the proportion of the oil in place located in the "Zama wing" below the spill point. This resulted in highly optimistic miscible recovery factors. Based on a two-dimensional mathematical study of Imperial's reef model, it concluded that a solvent bank would not sweep the "Zama wing". Imperial submitted that the maximum miscible recovery would be all the oil in place except that in the "Zama wing" and in a 20-foot sandwich zone in the main reef at the oil-water contact.

Imperial submitted that the recovery for the Muskeg pools under solvent flood would be very poor because "the bank would not sweep the Keg River reef or Zama member below the completion interval" and because sweep efficiency would be poor as a result of the off-centre well location.

Views of the Board. The Board does not agree with Hudson's Bay's method of determining a residual oil saturation of 32.5 per cent pore volume for the primary, gas flood and water flood depletion mechanisms because it neglected samples of low permeability. The Board has used a residual oil saturation of 38 per cent of pore volume in the calculation of the recovery factor for primary depletion, and 35 per cent of pore volume for the gas flood and water flood cases. These figures are based on residual oil saturation data from all available Keg River reef core samples. The Board adopted a residual oil saturation after solvent flood of 2 per cent of pore volume to account for losses in dead-end pore spaces.

The Board agrees with Hudson's Bay that the recovery will be affected by the quality of the reef and, having regard for possible reservoir flow barriers and reef quality, has adopted a conformance factor of 90 per cent for all mechanisms for all pools in the scheme. This conformance factor was applied to all pools since Hudson's Bay stated that an additional well would be drilled in those pools where the present well is located on the reef flank.

The Board estimated a final sandwich zone thickness for each recovery mechanism. In view of Hudson's Bay's procedure of calculating recovery based on the final oil saturation profile obtained from the mathematical simulators, the Board has no direct means of comparing the final sandwich losses.

Primary Depletion. The Board does not believe that Hudson's Bay has adequately accounted for the effect of water coning in determining the amount of oil remaining in the reservoir at abandonment.

It is estimated sandwich zone thicknesses ranging from 25 feet to 40 feet positioned just above the original oil-water contact at an economic producing limit of 15 barrels of oil per well per day. Using a residual oil saturation of 38 per cent pore volume which includes a 3 per cent pore volume loss due to viscous effects, the primary recovery factor was calculated for each pool. The Board believes some oil will be recovered by fluid expansion from the Zama member below the Lower Anhydrite spill point and in its calculation has estimated that 4 per cent of this oil would be recovered. Based on the past pool performance the Board has established a primary recovery of 30 per cent for the Zama Keg River C Pool. Table 3 shows the primary recovery factors as calculated by the Board.

Gas Flood. The Board has estimated, for the gas flooding mechanism, a sandwich zone thickness of 20 feet at a terminal producing rate of 10 barrels of oil per well per day. Using a residual oil saturation of 35 per cent of pore volume the recovery factors shown in Table 3 were calculated for the Zama Keg River U Pool and Zama Keg River FF Pool. No recovery was assigned to the Zama member below the spill point. For the Zama Keg River C Pool the Board adopted a recovery factor of 35 per cent having regard for its past performance.

Water Flood. The Board estimated for the Zama Muskeg L Pool an oil sandwich zone of 15 feet at a terminal producing rate of 10 barrels of oil per day per well at the crest of the pool assuming that a second well would be drilled in the crestal regions of the pool. A residual oil saturation of 35 per cent of pore volume was used to determine the flushing efficiency. Using these data the Board calculated a water flood recovery factor of 47 per cent for the Zama Muskeg L Pool as shown in Table 3.

Solvent Flood. For the solvent flood mechanism an oil sandwich zone of 20 feet was estimated by the Board at a terminal oil production rate of 10 barrels per day per well. An ultimate recovery factor for each pool was calculated assuming no recovery below the Lower Anhydrite spill point, a residual oil saturation of 2 per cent pore volume in the miscibly swept region, and the oil loss in the secondary gas cap as determined by Hudson's Bay.

The volumetrically weighted average solvent flood recovery factor was calculated to be 71 per cent as compared with the volumetrically weighted average of 75 per cent and 51 per cent determined by Hudson's Bay and Imperial respectively. The differences between the recovery factors calculated by Hudson's Bay and the Board are largely due to differences in the geological model and the conformance factor.

The Board notes that Imperial adopted the oil-in-place values proposed by Hudson's Bay and used its own geological model in the recovery calculations. The large difference in recovery between the Board and Imperial is directly related to the volume of oil contained in the Zama wing below the Lower Anhydrite spill point which will not be contacted by the solvent flood.

The Board does not agree with Imperial that the solvent flood recovery from Muskeg pools would be very poor. On the basis of Hudson's Bay's intention to drill an additional well in each Muskeg pool, the Board believes that the recovery from these pools will be comparable to other pools in the proposed scheme.

PRODUCTION SCHEDULE

Views of Hudson's Bay. Hudson's Bay stated that in view of the limited supply of solvent and the oil productivity limitations the integrated scheme would be operated in the following manner using five different phases involving the groups of pools shown in Figure 5.

1. Interim Phase - Complete the gas plant; place Zama Keg River FF Pool and Zama Keg River U Pool on gas injection; keep Zama Muskeg L Pool as water disposal pool and complete rate scheduling through coning studies and finalization of solvent bank studies.

2. Phase I - Place solvent bank in the pools in Group 1. Inject surplus dry gas from the gas plant into Group 2 and Group 3 pools for repressuring purposes.

3. Phase II - Place solvent bank in Group 2 pools. Inject surplus dry gas to Group 1 pools for the purpose of displacing the solvent bank and in Group 3 pools for repressuring purposes.

4. Phase III - Regeneration of solvent produced from Group 1 pools and the placement of solvent banks in individual or small groups of pools of the Group 3 pools. Inject dry gas to Groups 2 and 3 pools for solvent bank displacement purposes and to Group 4 pools for repressuring purposes.

5. Phase IV - Regeneration of solvent produced from Groups 1 and 2 pools and the placement of the solvent bank to the remaining pools in the scheme to be solvent flooded.

Hudson's Bay said that the scheduling of the 25 separate Zama pools for the integrated scheme cannot be rigorous at this time since solvent bank sizes and the resulting injection periods will depend on allowables and individual well rate schedules as dictated by coning and stable rate criteria.

Hudson's Bay used five different production rates to study the effect of solvent bank placement and solvent and gas coning. The case A (Table A, Section VI, Exhibit 3) which is based on 500 barrels per day for the first two years, 1000 barrels per day for the next 2.23 years, 500 barrels per day for 5.49 years and 250 barrels per day for the remaining life of the pool was considered by Hudson's Bay as being the representative production schedule for the pools in the proposed scheme. However, it stated that the aforementioned rates could be modified depending upon the allowables, the performance

and the solvent and gas coning behaviour. Hudson's Bay had not determined the interrelationship of the production amongst the pools but contended that flexibility in the proposed scheme would permit operation at an acceptable rate. In pools where solvent and gas coning could be a problem, the production rates would be reduced. It also stated that severe coning could occur in the flank wells and in these cases additional wells would be drilled to ensure proper solvent coverage and reduction in the solvent and gas coning.

Hudson's Bay, based on its mathematical coning simulator study, concluded that water coning would not likely occur with production rates of 1000 barrels per day. Hudson's Bay stated that none of its pools in the proposed scheme have shown any significant water production. It contended that the production rates are designed to offset any problem due to water coning at the end of the pool life when the perforations will be very close to the oil-water contact. Hudson's Bay, in response to Board questioning, stated that water coning could be a problem in some cases, but it had not attempted to account for it in its studies.

Views of the Board. The Board notes that Hudson's Bay's study has dealt in considerable detail with the problem of solvent and gas coning but has not considered the effect of possible water coning. The Board made an independent study using its two dimensional radial mathematical model to calculate the effect of water coning and solvent coning using the production schedule proposed by Hudson's Bay. The study indicated that at the proposed production rate a water cone will develop early in the life of the pool. The Board in its miscible recovery calculations used a production schedule which minimized water coning and provided a sandwich loss of 20 feet at the end of the pool life. Based on the more restricted production schedule, the Board calculated a total life of 30 to 35 years for the pools in the scheme.

The calculations described above indicate that coning of water could be a problem. The Board, however, believes that sequential depletion maximizes the production rate in any given pool to that limited by either coning or critical rate and that full advantage is taken of each pool's early high productivity.

While Hudson's Bay has not made a firm production schedule, the Board believes that it should conduct a further study to adequately resolve the interrelated problems of allowables to be produced, solvent, gas and water coning, critical rate, completion intervals and well bores needed.

The Board agrees with Hudson's Bay's plan to operate the pools of the scheme under five different phases to provide the necessary flexibility in production schedule operations and solvent bank placement operations. The attached Figure 5 indicates Hudson's Bay's proposed plans for grouping of the different pools in the scheme.

PROJECT MONITORING

Views of Hudson's Bay. Hudson's Bay stated that a monitoring schedule would be established to measure pool pressure, to detect the position of the solvent bank and solvent and gas coning, and to control the solvent composition. It said that special attention will be given to the Group 1 pools to permit any modification to be made to the subsequent operations in the other groups. Hudson's Bay plans to use chromatographic or other stream analysis to control the injected solvent composition. It will also implement a rigorous program for corrosion monitoring because of the high hydrogen sulphide content of the proposed solvent. It stated at the hearing that studies are in progress to investigate the use of radioactive tracers for the monitoring of the solvent flood front.

Hudson's Bay contended if inter-poolinterference is observed in some of the pools, injection of solvent and gas and possibly water will be considered to at least partially offset interference effects.

Views of the Board. The Board concurs with Hudson's Bay's proposed monitoring program. However, it considers it important that the oil-water interface of all the pools in the proposed scheme be closely monitored to observe any pool interference effects.

The Board agrees with Hudson's Bay that the reservoir pressure in all the pools should not be permitted to drop below 2000 psig.

INTER-REEF COMMUNICATION

Views of Hudson's Bay. Hudson's Bay stated that it recognized that some inter-reef communication exists in areas of the Zama-Virgo Field and has grouped the pools to minimize pressure interference to neighbouring reefs. Hudson's Bay stated that it plans to take reasonable measures to offset any detrimental effects through inter-reef communication.

Views of Atlantic Richfield. Atlantic Richfield intervened at the hearing stating that the Virgo Keg River Q Pool and Zama Keg River VV Pool should be deleted from the integrated scheme because the present pressure performance of the pools in this area of the application has indicated that there is some pressure communication through the aquifer between the aforementioned pools and the Atlantic Richfield's Virgo Keg River T Pool and the Zama Keg River N3N Pool. Atlantic Richfield stated that since the maintenance of the pressure in the Virgo Keg River Q Pool and the Zama Keg River VV Pool will not begin for about two years, the inclusion of these pools would have an adverse effect on enhanced recovery plans for its pools in the area.

Views of the Board. The Board believes that there could be inter-reef communication to varying degrees between the proposed pools of the scheme and surrounding pools. Through a proper monitoring

procedure the Board believes that any inter-reef communications could be detected sufficiently early to permit adequate measures to be taken to offset any significant adverse effects.

SUITABILITY OF THE PROPOSED ENHANCED RECOVERY SCHEMES

Views of Hudson's Bay. Hudson's Bay has applied under section 38 of The Oil and Gas Conservation Act, 1969, for approval of a scheme for the solvent flooding of 24 pools as specified under the heading of "The Application and Hearing" of this decision report and for gas flood for the Zama Keg River C Pool. Hudson's Bay stated that the Zama Keg River C Pool was not considered as being a suitable candidate for solvent flooding because of its size and the poor well bore properties of the well completed in the pool.

Views of the Board. The Board has considered the evidence and made its own evaluation of the miscibility, solvent bank size, solvent bank placement and recovery factor issues. The Board has also calculated the recovery factors of these same pools on primary depletion, gas flood, water flood and solvent flood.

The Board notes that the recovery under the mechanisms proposed is dependent on the height of the Lower Anhydrite and to a greater extent on the volume of oil in the Zama member below the Lower Anhydrite spill point. While the Board does not agree entirely with Hudson's Bay's interpretation of pool configuration, as discussed under the heading "Reservoir Description", the recovery factors agree reasonably well. The Board therefore agrees with Hudson's Bay's proposal for solvent flooding of the 24 pools. The Board in its analysis has assumed that an additional well will be drilled in those pools where the present well is located on the flank of the reef. The Board agrees with Hudson's Bay that, due particularly to the poor production performance, the Zama Keg River C Pool is not a good candidate for a solvent flood depletion mechanism and should be gas flooded. The Board agrees with Hudson's Bay that the increase in reserves through gas flooding the Zama Keg River C Pool could only be accomplished through the integrated aspects of its scheme.

The recovery factors and recoverable oil for the subsisting primary mechanisms, the oil in place values, solvent flood recovery factors and the ultimate recoverable oil as determined by the Board are summarized in Tables A and B following. These tables, together with Table 3 illustrate the gains in recoverable oil attainable through solvent flooding.

TABLE A

SUMMARY OF RECOVERABLE RESERVES AS DETERMINED BY BOARD

Pool	Oil in Place (MSTB)	Subsisting Primary Depletion Mechanism: Recovery Factor %	Subsisting Primary Depletion Mechanism: Ultimate Reserves (MSTB)	Solvent Flood: Recovery Factor %	Solvent Flood: Ultimate Reserves (MSTB)
(1)	(2)	(3)	(4)	(5)	(6)
Zama KR A	5,500	39	2,150	71	3,910
Zama KR C	2,000	30	600	--	--
Zama KR D	3,000	40	1,200	71	2,130
Zama KR E	2,500	41	1,030	.70	1,750
Zama KR F	5,500	38	2,090	69	3,800
Zama KR S	5,500	38	2,090	71	3,910
Zama KR U	4,500	37	1,670	72	3,240
Zama KR EE	6,500	38	2,470	71	4,620
Zama KR FF	8,000	42	3,360	76	6,080
Zama KR PP	4,800	42	2,020	71	3,410
Zama KR QQ	2,200	43	946	72	1,580
Zama KR VV	8,500	41	3,490	70	5,950
Zama KR XX	3,000	41	1,230	68	2,040
Zama KR AAA	6,000	41	2,460	73	4,380
Zama KR JJJ	3,000	36	1,080	69	2,070
Zama KR OOO	5,000	36	1,800	71	3,550
Zama KR RRR	6,500	38	2,470	71	4,620
Zama Mu L	2,300	40	920	70	1,610
Zama Mu O	1,800	31	558	71	1,280
Zama Mu EE	1,500	39	585	64	960
Virgo KR G	2,900	40	1,160	69	2,000
Virgo KR L	1,200	33	396	63	756
Virgo KR Q	3,500	41	1,440	70	2,450
Virgo KR GG	4,000	30	1,200	63	2,520
Virgo Mu D	1,500	39	585	66	990
		Totals	39,000		69,606

TABLE B

SUMMARY OF RECOVERABLE RESERVES

Pool	Oil in Place (MSTB)	Interim Depletion Mechanism: Mechanism	Interim Depletion Mechanism: Recovery Factor %	Interim Depletion Mechanism: Ultimate Reserves (MSTB)	Gas Flood: Recovery Factor %	Gas Flood: Ultimate Reserves (MSTB)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Zama KR C	2,000	Gas Flood	35	700	35	700
Zama KR U	4,500	Gas Flood	42	1,890	--	--
Zama KR FF	8,000	Gas Flood	47	3,760	--	--
Zama Mu L	2,300	Water Flood	47	1,080	--	--

The Zama Keg River U Pool for the interim period will be assigned a gas flood recovery factor of 42 per cent, 90 days following the initiation of gas injection to this pool. The Zama Keg River FF Pool for the interim and upon reactivation of gas injection to the pool will be assigned a gas flood recovery factor of 47 per cent.

The Zama Muskeg L Pool will be assigned, for the interim commencing December 1, 1970, a water flood recovery factor of 49 per cent. For pools other than the Zama Muskeg L Pool, the primary recovery factor shown in Table A will be assigned effective December 1, 1970. Upon qualification of solvent flood recovery factor modifier for the Group 1 pool or pools by bank placement in the Group 1 pools, the solvent flood recovery factor and ultimate reserves shown in Table A will be assigned to all pools except the Zama Keg River C Pool in which a gas flood recovery factor and gas flood reserves will be applied.

CONSERVATION ADVANTAGES OF THE PROPOSED INTEGRATED OPERATIONS

Consideration of the application under section 34, subsection (2) for an aggregate allowable requires demonstration that a significant increase in oil conservation would result because of the integrated scheme. Oil conservation gains may occur to a sequential depletion by solvent flood by more efficient utilization of the available gas and solvent supplies or by the application of a more efficient recovery mechanism to more oil in place than would be otherwise possible under concurrent depletion.

This matter is discussed under the headings of "Gas and Solvent Supply" and "Advantages of Integrated Operations".

(1) Gas and Solvent Supply

<u>Views of Hudson's Bay</u>. Hudson's Bay estimated that about 76 Bcf of displacement gas is required to solvent flood the proposed pools assuming that all pools would be full of high pressure gas at the termination of the scheme. It estimated that about 22.3 Bcf of non-associated gas is available from the Keg River formation and 18.1 Bcf from solution gas produced from Hudson's Bay's pools. Hudson's Bay stated that it will be necessary to reuse the displacement gas in other pools and as a safety factor about 35 Bcf of displacement gas will be available from the Bistcho and Slave Point formations in nearby pools.

Hudson's Bay in its post-hearing documents stated that approximately 15.9 million reservoir barrels of solvent would be required to miscibly flood the 24 pools whereas about 11.7 million reservoir barrels will be available from the Keg River non-associated gas and solution gas. The deficit of 4.2 million reservoir barrels of solvent will be obtained by regeneration of solvent production from the pools undergoing solvent flood. Hudson's Bay further stated

that as a safety factor about 3 million reservoir barrels of solvent will be available from the Bistcho and Slave Point formations when required. If the pools in the scheme were concurrently depleted, either the solvent bank size would be reduced or some pools dropped from the scheme.

Views of the Board. The Board estimates that about 68 Bcf of displacement gas will be required to solvent flood the proposed pools based on a volumetric average oil recovery factor of 71 per cent for the proposed pools of the scheme. The Board does not agree with Hudson's Bay's determination of gas available from the Keg River non-associated gas reserves. It estimates that approximately 9 Bcf of displacement gas will be available from proven Keg River non-associated reserves but has not assigned any reserves to the unproven non-associated category. The Board agrees with Hudson's Bay's estimate of 18.1 Bcf of gas available from Keg River solution gas and 35 Bcf of gas from the Slave Point and Bistcho sources. The total gas available for displacement purposes is estimated to be 62 Bcf, resulting in a deficit of about 6 Bcf of displacement gas without reuse of injected gas. With reuse of injected gas sufficient gas should be available for displacement purposes.

On the basis of a solvent bank size of 16 per cent the Board estimates that about 19 million reservoir barrels of solvent will be required. The Board estimates that about 8 million reservoir barrels of solvent will be available from the Keg River non-associated gas and solution gas and 3 million reservoir barrels from the Slave Point and Bistcho formations for a total of 11 million reservoir barrels of solvent. The Board estimated that about 5 million reservoir barrels of solvent produced from Groups 1 and 2 pools through coning will be regenerated and available for injection to the other pools in the proposed scheme, thus leaving a deficiency of 3 million barrels of solvent. The Board recognizes that this deficit could be made up from further development of unproven Keg River non-associated gas reserves and other sources but believes that Hudson's Bay should clearly demonstrate that it has sufficient solvent supply to meet the total solvent requirement.

The Board understands that the design output capacity of the gas plant would be adequate to provide an initial volume of 7.4 million cubic feet per day of sour residue gas and about 2,000 reservoir barrels per day of solvent. This would be sufficient on a daily basis to replace the withdrawals from the pools of the scheme.

(2) Advantages of Integrated Operations

Views of Hudson's Bay. Hudson's Bay stated that simultaneous solvent injection to each pool would result in smaller banks or in some pools not being solvent flooded. This would reduce ultimate recovery by 5 million stock tank barrels. Furthermore, because of the longer

residence time in each pool, miscibility would break down earlier than under a sequential scheme and would result in a reduction of an additional 2 million stock tank barrels. Hudson's Bay therefore contended that the integrated depletion scheme would recover about 7 million stock tank barrels more than the recoverable reserves from the concurrent solvent depletion of the proposed pools. Hudson's Bay stated that "an integrated scheme will permit sufficient flexibility to allow each pool under miscible flood to be produced in accordance with its optimum coning stability rate schedule". In view of some pressure communication in some of the pools, Hudson's Bay commented that "an integrated sequential miscible displacement scheme will be a success if it is well engineered and closely monitored".

Hudson's Bay said that, in view of the small gain in recoverable reserves, it would be marginally economic to gas flood the Zama Keg River C Pool separately. By including the pool in the integrated scheme the pool could initially remain shut in until gas for injection purposes is available from the gas line completed for the injection into the Group 4 pools. The increase in ultimate reserves resulting from gas flooding this pool is 90,000 stock tank barrels.

Hudson's Bay stated that a sequential depletion scheme would result in smaller banks due to shorter depletion times and that an integrated scheme would also permit the transfer of production to other pools during periods when a particular pool would be rate restricted due to producing limitations imposed by critical rate restrictions and solvent coning.

Views of the Board. The Board concurs with Hudson's Bay that the sequential scheme will result in about a 7 million stock tank barrel increase in reserves attainable over concurrent solvent flood. Moreover the Board believes that there is a more efficient use of solvent and displacement gas under a sequential depletion scheme. It would also provide flexibility in production rates from pool to pool as certain pools become productivity limited.

THE UNDERTAKING OF THE OPERATORS

Hudson's Bay stated that it is prepared to continue the proposed scheme to depletion. The Board accepts this undertaking.

RELIABILITY OF RESERVES ESTIMATES

The reserves determined for the pools in the integrated schemes have been based on the limited pressure-production history and on a limited well control. The established oil in place values were based largely on a reservoir model based on individual well data and seismic data.

The Board expects that the reserves of those pools which will be on primary depletion until being placed on solvent flood will be

re-evaluated consistent with the normal practice using pressure-production information. For the pools that will be produced under a miscible displacement mechanism the Board believes that the reserve estimates are as good as for other comparable pools in the Province at the same stage of depletion.

DECISION

1. The Board approves, under section 38 of The Oil and Gas Conservation Act, 1969, the scheme for enhanced recovery by

(a) solvent flood for those pools as shown in Table A of this decision report except for the Zama Keg River C Pool,

(b) gas flood for the Zama Keg River C Pool,

(c) for an interim period until the commencement of solvent injection and recognition of enhanced recoverable reserves in accordance with decision 5 below, gas flood for the Zama Keg River U and Zama Keg River FF Pools, and

(d) for an interim period until the commencement of solvent injection and recognition of enhanced recoverable reserves in accordance with decision 5 below, water flood for the Zama Muskeg L Pool.

The Board further approves, under section 34 subsection (2) of The Oil and Gas Conservation Act, 1969, the carrying out of these operations on an integrated basis. The terms and conditions of the approval of the integrated scheme are specified in Approval No. 1383 issued concurrently with this decision.

2. Effective December 1, 1970, the ultimate recoverable reserves under the existing depletion mechanism except for the Zama Muskeg L Pool are established as shown in column 4 of Table A of this decision report, and for the Zama Muskeg L Pool the ultimate recoverable reserves under water flood are established as shown in column 5, Table B.

3. Effective at a time in accordance with section 914 of the Oil and Gas Conservation Regulations, the ultimate recoverable reserves for the Zama Keg River U Pool under gas flood are established as shown in column 5, Table B.

4. Effective upon the reactivation of gas injection to the Zama Keg River FF Pool the ultimate recoverable reserves for the Zama Keg River FF Pool are established as shown in column 5, Table B.

5. Effective at the time or times appropriate in accordance with section 914 of the Oil and Gas Conservation Regulations, the ultimate recoverable reserves under solvent flood except for the Zama Keg River C Pool are established as shown in column 6, Table A and an ultimate recoverable reserves under gas flood for the Zama Keg River C Pool as shown in column 7, Table B.

6. Hudson's Bay shall satisfy the Board, prior to receiving recognition of the ultimate recoverable reserves under solvent flood in accordance with decision 5, with its plan to acquire the additional solvent reserves necessary to meet the solvent requirement for the proposed scheme.

7. Consistent with the recovery factors calculated Hudson's Bay shall attempt to keep production from pools not undergoing solvent flood to a minimum and shall provide to the Board a schedule of production and injection rates for all pools in the proposed scheme, prior to the commencement of injection of solvent and gas to the pools in Group 1.

8. The Board grants, effective on the commencement of the proration period following or coincident with the commencement of solvent and gas injection substantially in accordance with the scheme approved, the application under section 34, subsection (2) of The Oil and Gas Conservation Act, 1969, for a variation in the manner in which the provincial allowable for crude oil is allocated among the pools of the integrated scheme and for the fixing, in the Board's MD Order, of a single aggregate amount of crude oil that may be produced from the group of pools.

OIL AND GAS CONSERVATION BOARD

G. W. Govier
Chairman

DATED at Calgary, Alberta
November 9, 1970

OIL AND GAS CONSERVATION BOARD

TABLE 1 TO DECISION 70-7

COMPARATIVE RESERVOIR PARAMETERS AND OIL IN PLACE FROM SUBMISSION AND AS SET BY THE BOARD

Pool	Oil Zone Res. Vol. (acre ft)		Area (acres)		Thickness, H (feet)		Porosity, Ø (fraction)		Water Sat., Sw (fraction)		Shrinkage 1/Boi		Oil in Place, N (MSTB)	
	HBOG	Board	HBOG	Board(3)	HBOG	Board	HBOG	Board	HBOG	Board	HBOG	Board	HBOG	Board
Zama KR(1) A	14,000	13,000	160	80	228	210	0.071	0.071	0.10	0.11	0.864	0.86	6,000	[illegible]
Zama KR C	4,450	4,580	160	32	278	270	0.077	0.077	0.14	0.16	0.876	0.87	2,000	[illegible]
Zama KR D	6,000	7,500	160	50	316	375	0.074	0.074	0.12	0.16	0.825	0.83	2,500	3,000
Zama KR E	6,370	6,540	160	41	157	158	0.070	0.070	0.10	0.12	0.803	0.80	2,500	2,500
Zama KR F	15,480	13,400	160	83	164	167	0.071	0.071	0.10	0.12	0.847	0.85	6,500	5,500
Zama KR S	12,090	12,400	160	73	303	300	0.079	0.079	0.15	0.16	0.873	0.86	5,500	5,500
Zama KR U	10,980	11,800	160	76	191	192	0.074	0.074	0.12	0.18	0.811	0.81	4,500	4,500
Zama KR EE	15,000	15,300	160	97	195	186	0.070	0.070	0.10	0.12	0.888	0.89	6,500	6,500
Zama KR FF	22,000	19,700	160	96	286	286	0.071	0.071	0.10	0.11	0.825	0.83	9,000	8,000
Zama KR PP	13,200	11,500	160	63	340	325	0.074	0.074	0.10	0.10	0.808	0.81	5,500	4,000
Zama KR QQ	5,380	5,460	160	33	173	181	0.073	0.073	0.10	0.11	0.802	0.80	2,200	2,200
Zama KR VV	25,800	19,600	160	103	301	301	0.075	0.075	0.12	0.10	0.83	0.83	11,000	8,500
Zama KR XX	6,932	7,280	160	47	220	224	0.071	0.071	0.10	0.11	0.873	0.84	3,000	3,000
Zama KR AAA	17,040	14,700	160	80	318	355	0.074	0.074	0.10	0.10	0.795	0.79	7,000	6,000
Zama KR JJJ	7,140	7,860	160	57	152	150	0.070	0.070	0.11	0.20	0.869	0.88	3,300	3,000
Zama KR OOO	11,730	11,600	160	81	162	167	0.074	0.074	0.12	0.19	0.928	0.93	5,500	5,000
Zama KR RRR	18,700	19,200	160	109	231	231	0.074	0.074	0.15	0.17	0.713	0.71	6,500	6,500
Zama Mu(2) L	5,754	6,220	160	38	158	210	0.070	0.070	0.11	0.18	0.827	0.83	2,300	2,300
Zama Mu O	4,280	4,450	160	29	77	162	0.069	0.069	0.10	0.09	0.825	0.83	1,700	[illegible]
Zama Mu EE	5,250	3,540	160	26	87	105	0.069	0.069	0.10	0.09	0.869	0.87	2,200	1,500
Virgo KR G	6,690	7,220	160	43	306	300	0.077	0.077	0.14	0.16	0.800	0.80	2,750	2,900
Virgo KR L	2,790	2,990	160	36	124	124	0.084	0.084	0.16	0.22	0.786	0.79	1,200	[illegible]
Virgo KR Q	8,350	8,790	160	55	205	374	0.071	0.071	0.10	0.14	0.842	0.84	3,500	3,500
Virgo KR GG	12,850	11,900	160	169	92	94	0.069	0.069	0.10	0.14	0.727	0.73	4,500	4,000
Virgo Mu D	4,350	3,740	160	65	122	121	0.069	0.069	0.10	0.13	0.859	0.86	1,800	1,500
									TOTAL				108,950	10[illegible],700

(1) Keg River pool

(2) Muskeg pool

(3) Area at the oil-water contact using the Board Zama (mushroom) model

OIL AND GAS CONSERVATION BOARD

TABLE 2 TO DECISION 70-7

SOLVENT BANK SIZE

Pool	Solvent Bank Size M Res. Bbls	
	HBOG*	Board**
Zama Keg River A	875	1020
Zama Keg River D	395	580
Zama Keg River E	405	500
Zama Keg River F	995	1040
Zama Keg River S	820	1020
Zama Keg River U	720	880
Zama Keg River EE	910	1170
Zama Keg River FF	1340	1540
Zama Keg River PP	820	950
Zama Keg River QQ	355	440
Zama Keg River VV	1720	1640
Zama Keg River XX	445	570
Zama Keg River AAA	825	1220
Zama Keg River JJJ	495	550
Zama Keg River OOO	700	860
Zama Keg River RRR	1135	1470
Zama Muskeg L	285	440
Zama Muskeg O	270	350
Zama Muskeg EE	250	280
Virgo Keg River G	445	580
Virgo Keg River L	200	240
Virgo Keg River Q	415	670
Virgo Keg River GG	805	880
Virgo Muskeg D	240	280

* Hudson's Bay solvent bank size is based on 13 per cent of the hydrocarbon pore volume.

** Board solvent bank size is based on 16 per cent of the hydrocarbon pore volume.

OIL AND GAS CONSERVATION BOARD

TABLE 3 TO DECISION 70-7

COMPARISON OF RECOVERY FACTORS FOR DIFFERENT RECOVERY MECHANISMS

Pool	Primary Per Cent		Gas/Water Flood Per Cent		Solvent Flood Per Cent		
	HBOG	Board	HBOG	Board	HBOG	Imperial	Board
Zama KR A	47	39	--	--	80	4[illegible]	[illegible]
Zama KR C	43	30	47*	35*	--	--	--
Zama KR D	47	40	--	--	81	56	71
Zama KR E	54	41	--	--	88	57	70
Zama KR F	52	38	--	--	84	49	69
Zama KR S	56	38	--	--	88	49	71
Zama KR U	47	37	57.2*	42*	82	50	72
Zama KR EE	49	38	--	--	81	49	71
Zama KR FF	48	42	57.5*	47*	82	50	76
Zama KR PP	38	42	--	--	67	58	71
Zama KR QQ	44	43	--	--	79	27	72
Zama KR VV	51	41	--	--	81	61	70
Zama KR XX	53	41	--	--	84	54	68
Zama KR AAA	30	41	--	--	52	55	73
Zama KR JJJ	42	36	--	--	76	48	69
Zama KR OOO	44	36	--	--	76	48	71
Zama KR RRR	40	38	--	--	70	53	71
Zama Mu L	38	40	43.4**	47**	62	--	70
Zama Mu O	55	31	--	--	90	--	71
Zama Mu EE	29	39	--	--	55	--	64
Virgo KR G	40	40	--	--	71	64	69
Virgo KR L	36	33	--	--	69	66	63
Virgo KR Q	35	41	--	--	55	31	70
Virgo KR GG	38	30	--	--	71	51	63
Zama Mu D	35	39	--	--	64	--	66
			WEIGHTED AVERAGE:		75.0	51.3	70.[illegible]

* Gas Flood Recovery Factor

** Water Flood Recovery Factor

OIL AND GAS CONSERVATION BOARD

Decision 70-8
Application No. 5140

GAS PROCESSING
STRACHAN AND RICINUS WEST FIELDS

THE APPLICATION AND HEARING

Banff Oil Ltd. applied under section 38, clause (b) of The Oil and Gas Conservation Act, 1969, for approval of a scheme for the processing of gas produced in the Strachan and Ricinus West Fields. The plant, to be located in Section 2, Township 37, Range 10, West of the 5th Meridian, would have a daily capacity of 220 million cubic feet of raw gas and produce 150 million cubic feet of marketable gas, 1,992 long tons of sulphur, and 3000 barrels of pentanes plus. The applicant proposed that the initial sulphur recovery efficiency would be 95 per cent for a period not to exceed three months and thereafter would be 98 per cent. The sulphur not recovered would be emitted to the atmosphere as sulphur dioxide through a stack 300 feet in height. Prior to the hearing by the Oil and Gas Conservation Board the location of the proposed plant had been considered and had been approved by the Provincial Board of Health, the Department of Lands and Forests and Improvement District No. 10. At the time these approvals were granted the amended Oil and Gas Conservation Regulations concerning pollution control at gas processing plants were not in effect.

Raw gas production of 90 and 130 million cubic feet per day would originate from the Strachan D-3 A Pool and Ricinus West D-3 A Pool respectively. The design of the processing plant provides for an increase of capacity to 440 million cubic feet per day of raw gas from the Ricinus West D-3 A Pool should future drilling establish the necessary reserves anticipated by the applicant.

The plant facilities would consist of inlet separation, gas treating, dew point control, condensate stabilization and sulphur recovery. The sulphur recovery facilities would consist of two, two-stage Claus type plants followed by a Sulfreen tail gas sulphur recovery unit. The sulphur recovery efficiency would be maintained at a high level through the use of an optimizer. Banff stated that the Sulfreen process has been installed and is operating satisfactorily on an industrial scale in a gas processing plant owned by Societe Nationale des Petroles d'Aquitane in Lacq, France. The applicant anticipates that the Sulfreen unit may not be available for operation for up to three months after the start up of the rest of the plant.

The sulphur plant incinerator stack would be provided with a continuous stack emission monitoring system to monitor the flue gas sulphur dioxide concentration and emission rate.

The application was heard on September 14, 1970 by Board Members G. W. Govier, P. Eng., A. F. Manyluk, P. Eng. and V. Millard.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Banff Oil Ltd.	L. C. Cameron, P. Eng. J. E. Martin, P. Eng. J. A. Pope, P. Eng.	Banff
Department of Health	P. M. Ullman, P. Eng.	
Board Staff	L. A. Mazurek, P. Eng. R. B. Dunbar, P. Eng.	

DEFINITION OF ISSUES INVOLVED

The Board considers the following to be the main issues:

1. The location of the plant.

2. The adequacy of the levels of conservation of sulphur and hydrocarbons proposed.

3. The adequacy of the pollution control measures proposed.

Involved in both items 2 and 3 is the issue of the adequacy of the measurement of the input and output streams of the plant.

PLANT SITE

(1) Views of the Applicant

The Applicant stated that the following approvals respecting the proposed plant site had been obtained prior to the coming into effect, August 1, 1970, of the current Oil and Gas Conservation Regulations concerning applications for approval of schemes for the processing of gas:

(a) Site approval from the Department of Lands and Forests on March 24, 1970,

(b) Site approval from Improvement District No. 10 on March 26, 1970,

(c) Provisional air pollution approval from the Department of Health on March 31, 1970, involving approval of the site, for a plant with a raw gas capacity of 440 million cubic feet per day.

(2) Views of the Board

The Board invited further representations concerning the site and since none were received and since the plant site had been previously approved by the other concerned agencies, the Board finds the plant site satisfactory.

CONSERVATION LEVELS

(1) Views of the Applicant

The applicant indicated that a sulphur recovery efficiency of 95 per cent would be achieved during the first three months of operation of the two stage Claus type plant prior to start-up of the Sulfreen Unit. This relatively high recovery efficiency would result from the fresh catalyst, special mechanical design features of the plant and automatic sulphur plant control through use of the plant optimizer. Banff expects to be able to maintain 98 per cent sulphur recovery efficiency after start-up of the Sulfreen Unit based on experience in successfully operating a Sulfreen tail gas unit at Lacq, France. Some operational difficulties would be expected for up to twelve months after the Sulfreen unit start-up date. For this reason Banff requested that the average sulphur recovery efficiency be calculated over periods longer than the one-month periods over which such efficiencies are normally calculated under present practice.

The applicant stated that every effort would be taken to conserve hydrocarbons to the satisfaction of the Board. Flaring would occur only during emergencies and would be kept to an absolute minimum. The applicant also stated that measurement of all gas volumes, liquid volumes and sulphur production would be carried out to the satisfaction of the Board.

(2) Views of the Department of Health

The Department of Health, concerned with the quantity of sulphur compounds which would be released to the atmosphere, expressed concern that, based on actual experience with other plants, a sulphur recovery efficiency of 93 per cent would be more realistic than the 95 per cent efficiency forecast for operation of the two stage sulphur plant prior to start-up of the Sulfreen Unit.

(3) Views of the Board

The Board is generally satisfied with the measures proposed for the conservation of sulphur and hydrocarbons. The Board agrees with the applicant that calculation of average sulphur recovery efficiency for periods longer than one month is reasonable, and it approves averaging sulphur recovery efficiencies at the plant over three-month periods. The Board believes that the concern of the Department of Health respecting plant efficiency would be satisfied by imposing an overall limit on the quantity of sulphur compounds discharged to the atmosphere. This matter is discussed further later in the report.

PROPOSED POLLUTION CONTROL MEASURES

(1) Views of the Applicant

The applicant stated that all necessary measures would be taken to ensure full compliance with current regulations and requirements concerning pollution of air, land and surface or subsurface water. The major specific provisions proposed and related comments follow:

(a) The 300 foot stack height was chosen to maintain the tree top concentration of sulphur dioxide in the area below the maximum prescribed by the regulations of 0.3 parts per million up to an elevation of 5300 feet.

(b) While the plant is operational at a raw gas rate of 220 million cubic feet per day and recovering 98 per cent of the sulphur in the feed to the plant, the emission of sulphur dioxide to the atmosphere would be a maximum of 82 long tons per day. The corresponding maximum tree top sulphur dioxide concentration below the 5300 foot level would be less than 0.3 parts per million.

(c) Trees of potential commercial value do not exist beyond the 5300 foot elevation of the ridges west of the plant.

(d) During the initial three months of operation of the plant the sulphur recovery efficiency would be 95 per cent. The tree top concentration of sulphur dioxide while processing 220 million cubic feet per day of raw gas may exceed 0.3 parts per million at elevations below 5300 feet if the wind is from the north-east and the wind speed is equal to or exceeds 15 miles per hour.

(e) Wind data gathered in the area over the last three years show that the winds were in excess of 15 miles per hour from the east or north-east direction less than one per cent of the time.

(f) The stack height was chosen to accommodate a possible future expansion of the plant to 440 million cubic feet per day of raw gas. Calculations indicate that the plant could be operated at this rate without tree top sulphur dioxide concentrations below the 5300 foot elevation exceeding 0.3 parts per million in all but the extreme conditions referred to in (d) above.

(g) In the event that the measured sulphur dioxide concentrations anywhere below the 5300 foot level exceed 0.3 parts per million immediate action would be taken at the plant to reduce the concentration to this level.

(h) A pitot tube device will be installed in the incinerator stack and an analyzer will be provided to continuously monitor the sulphur dioxide emission rate.

(i) Banff stated that the combined effect of sulphur dioxide emissions from the Banff and the Gulf Oil Canada Limited Strachan Plants would not result in sulphur dioxide concentrations in excess of the maximum permissible concentrations prescribed by regulations.

(j) If the sulphur product is not shipped as a liquid, Banff stated that it would ship the entire production in a slate, pelletized or similar form to minimize sulphur dust pollution.

(k) Banff proposes to take whatever precautions are necessary to prevent vapours from escaping from the pentanes plus storage tanks.

(l) Banff stated that the disposal of produced salt water, process water and process waste would be carried out to the satisfaction of both the Department of Health and the Board.

(2) Views of the Board

The Board is generally satisfied with the pollution control measures proposed for hydrocarbon vapours, sulphur compounds, sulphur dust and water. The Department of Health also appears satisfied. Having regard both to conservation and pollution control the Board accepts that some 82 long tons per day of sulphur and sulphur compounds, expressed as sulphur dioxide, may be discharged to the atmosphere. It believes that the discharge of sulphur and sulphur compounds should be limited to this level at all times from the start of plant operations.

DECISION

The Board grants the application subject to the operator limiting emissions of sulphur compounds to an equivalent of 82 long tons per day of sulphur dioxide at all times. In addition to other normal conditions the Board approval will require a sulphur recovery efficiency of 95 per cent for the first three months of operation and of 98 per cent for each quarter thereafter The approval will also require stack emissions to be measured on a continuous basis. The condition that Banff shall not flare gaseous hydrocarbons

1. from October 1, 1970 to December 31, 1971, in excess of one percent of the total volume delivered to the plant during each quarter, and

2. from January 1, 1972, and in each year thereafter, in excess of one-half of one per cent of the total volume delivered to the plant during each quarter,

will also be imposed by the Board.

OIL AND GAS CONSERVATION BOARD

Frank Manyluk

A. F. Manyluk
Deputy Chairman

DATED at Calgary, Alberta
November 13, 1970

OIL AND GAS CONSERVATION BOARD

DECISION 70-9
Applications No. 5224 and 5225

APPLICATION FOR AMENDMENT OF APPROVAL OF A SCHEME FOR THE DISPOSAL OF SALT WATER IN THE PINCHER CREEK FIELD

THE APPLICATION AND HEARING

Gulf Oil Canada Limited applied for amendment of Approval No. 623 and Approval No. 689 to permit disposal without limitation of volume, of water produced in conjunction with oil or gas from the Pincher Creek Field, Waterton Field, Lookout Butte Field and of process water from the Gulf Pincher Creek Gas Processing Plant.

The applications were initially advertised for objections in the Calgary Albertan and the Calgary Herald on July 28; and in the Edmonton Journal on July 29, 1970. Following receipt of objections the applications were set down for a hearing. The details of the hearing were published in advertisements in the Calgary Herald, the Edmonton Journal, the Pincher Creek Echo and the Lethbridge Herald between September 17 and September 24, 1970. The application was heard on October 8, 1970 in the Pincher Creek Court House, by the Board with G. W. Govier, P. Eng., and A. F. Manyluk, P. Eng. sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviations used in Report
Gulf Oil Canada Limited	R. K. Craig, P. Eng. J. F. Milne, P. Geo. R. E. Bowser, P. Eng. W. K. Good, P. Eng. J. G. Gainer, P. Eng.	Gulf
George Huddleston, Andrew G. Russell, E. R. Marr, J. C. Campbell, Mr. and Mrs. Wm. Yakubiec	Andrew G. Russell	
George S. Newton	George S. Newton	
E. Stenson	E. Stenson	
Mr. and Mrs. Jim Taylor	Mrs. Jim Taylor	

	Represented by	Abbreviations used in Report
Board Staff	L. E. Hicklin, P. Eng. V. E. Bohme, P. Eng. G. J. DeSorcy, P. Eng. C. Moore, C.E.T.	Board

The individual interveners listed are from the Pincher Creek and Twin Butte district and intervened to object to a number of points regarding the disposal of salt water. The hearing was held in Pincher Creek to give the people in the area an opportunity to hear the details of the applications and to enter their interventions.

DEFINITION OF THE ISSUES INVOLVED

In considering the application, the Board had regard for the following two main issues:

(1) Does the method of completion of the injection well virtually assure that there is no possibility of the injected salt water escaping from the well above the intended injection interval?

(2) Will the injection of larger volumes of water than now approved have any harmful effect on the subsurface strata which might result in the escape of water from the injection zone?

SUBMISSION OF THE APPLICANT

Gulf is currently disposing of water produced in the Pincher Creek, Waterton and Lookout Butte Fields into two wells, B.A. Pincher Creek IN 9-10-4-29 and B.A. Pincher Creek IN 6-1-4-29. These two wells have been used as disposal wells since 1964 and 1958 respectively. Gulf expects increasing volumes of water to be produced from the Pincher Creek and Lookout Butte Fields and wishes to commence injecting process water from its Pincher Creek Plant instead of disposing it to Drywood Creek. The current approvals limit the volume of water disposed to each well to 60,000 barrels per month. The volume of water to be disposed would exceed these limits in the near future and Gulf requested that the approvals be amended to eliminate the volume restriction.

Gulf presented diagrams of the completion of both injection wells, which showed that the wells were completed with surface casing, intermediate casing and production casing. The injection zones are from 13,112 to 13,594 feet in the 9-10-4-29 well and from 12,510 to 13,170 feet in the 6-1-4-29 well. Gulf stated that both wells would be equipped with production packers to seal the annular space between the tubing and the casing. The annular space above the packer would be filled with inhibited fresh water to prevent casing and tubing corrosion. All water would be injected through the tubing.

A geological cross-section of the Pincher Creek Field was presented which showed the injection interval to be the second sheet of the Rundle formation which is several hundred feet below the gas-water contact in the Pincher

Creek Field. Gulf contended that the interval is not in pressure communication with the water accumulation of the gas pool in the Pincher Creek Field. The latest pressure data in July 1969 indicated the static pressure at the disposal wells to be about 3,000 pounds per square inch (psi) higher than in the adjacent producing gas wells.

During examination by the Board staff, Gulf submitted that the static pressure in the injection zone had increased by about 450 psi since injection commenced. This pressure increase resulted from the injection of approximately 3,850,000 barrels of water up to December 31, 1969. Gulf estimated the injection rate in 1975 would be approximately 5,800 barrels per day but could not estimate the effect on the injection pressure. Gulf stated that it was unlikely the injection pressure would produce bottom-hole pressures in excess of the formation fracturing pressure, which has been found to exceed 13,000 psi. The applicant explained that pressure limitations on injection pumps would limit injection pressures and thus retain bottom-hole pressures at levels well below the fracture pressure.

SUBMISSION OF INTERVENERS

Andrew G. Russell

Mr. Russell objected to the placing of the initial notice regarding the application in a newspaper published and distributed 350 miles away from the area involved. He also expressed doubt regarding the methods of control of water disposal which apparently allow truck-loads of waste water to be dumped on public roads and allow waste water to get into ground water supplies. He stated that although this contamination had been brought to the attention of various government departments, no apparent efforts have been made to locate the source and supply information to residents regarding the contamination. (The Board has subsequently learned, with respect to the specific incident referred to by Mr. Russell, that information was supplied to the complainant.) He speculated that toxic elements which may have poisoned cattle in the area originate when the formations over the gas-bearing formation are fissured or faulted, allowing escape of salt water into fresh water strata.

George S. Newton

Mr. Newton commented that since the operation of sulphur plants began in the area, there has been a deterioration in domestic water quality. He submitted that injection under pressure of polluted water from plant processes could lead to pollution of deep seated water beds supplying artesian or deep water wells drilled farther east in Alberta.

E. Stenson

Mr. Stenson expressed the opinion that any increase of pollution of air, soil or water should be avoided wherever possible.

Mr. and Mrs. Jim Taylor

Mrs. Taylor objected on the basis that water from their well has been

found to have become chemically unfit for human consumption. She claimed that increased injection could further aggravate the situation. She further objected that the notice for objection did not appear in the local paper.

J. W. Meltzer

Mr. Meltzer was not present at the hearing but his letter of intervention was read into the record. He expressed absolute opposition to the granting of the application. He stated that he did "not think it fair that his entire life work be destroyed or damaged by the contamination of the underground water supply by a large non-resident foreign controlled corporation".

FINDINGS OF THE BOARD

(1) The Board is satisfied that the method of completion of the injection wells and their operation will not result in injected salt water escaping from the well above the intended injection formation. The Oil and Gas Conservation Regulations regarding completion, operation and testing of injection wells together with the Board's field surveillance program virtually assures that no contamination will result from the injection of water.

(2) The Board accepts Gulf's contention that it is unlikely injection pressure required in the next five years would produce bottom-hole pressures in excess of the fracture pressure in the formation. The Board has made its own calculations which confirm Gulf's estimates.

(3) The Board understands and appreciates the concern of the local residents for the possibility of some damage occurring to the injection zone, with a consequent risk of damage to subsurface potable water supplies, as a result of unlimited injection of water. The Board has considered this matter in detail and is satisfied that provided a limitation is placed upon the maximum well head injection pressure, to prevent fracturing of the reservoir, the injected water will be safely confined within the injection formation.

DECISION

The Board will grant the applications of Gulf Oil Canada Limited to amend the current approvals to dispose salt water into the wells, B.A. Pincher Creek IN 9-10-4-29 and B.A. Pincher Creek IN 6-1-4-29. To ensure that the formation to which water is being injected is not subjected to fracture pressures; the Board will restrict the well head injection pressure to 2,000 pounds per square inch. Gulf will be required to submit annually an analysis of the pressure performance of the formation to which the water is injected.

The amendments to the approvals are being issued concurrently with this decision.

OIL AND GAS CONSERVATION BOARD

G. W. Govier
Chairman

DATED at Calgary, Alberta
November 16, 1970

OIL AND GAS CONSERVATION BOARD

Decision 70-10
Proceeding No. 5204

PRESSURE MAINTENANCE PROGRAMS REVIEW
TURNER VALLEY RUNDLE POOL

A public hearing was called by the Board for the purpose of reviewing the operations of each of the pressure maintenance programs described in Board Order No. TVU 3, Order No. TVU 4, Order No. TVU 5 and Order No. TVU 6. Submissions were received from Western Decalta as operator of Turner Valley Unit No. 3 and Turner Valley Unit No. 4, by Gulf Oil Canada Limited as operator of Turner Valley Unit No. 5 and Home Oil Company Limited as operator of Turner Valley Unit No. 6.

The submissions were heard on September 17, 1970, by the Board, with Vernon Millard and D. R. Craig, P. Eng. sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Gulf Oil Canada Limited	G. A. McGuffin, P. Eng. T. E. Randall, P. Eng.	Gulf
Home Oil Company Limited	F. R. Erick Mulder, P. Eng.	Home
Western Decalta Petroleum Limited	R. D. V. Patel, P. Eng.	Western Decalta
Board Staff	D. G. Pearson, P. Eng.	

PROVISIONS OF ACT AND REGULATIONS

This proceeding was held pursuant to the provisions of The Turner Valley Unit Operations Act.

DEFINITIONS OF ISSUES INVOLVED

The last annual hearing to consider the performance of each of the pressure maintenance programs in the Turner Valley Field was held on September 9, 1968. Following the hearing the Board amended the respective orders to provide that for the period July 1, 1968 to June 30, 1969 at least 100 per cent of the volume of total fluids withdrawn from each of Unit 3, 5 and 6 and Part 1 of Unit 4 be replaced by water injection. The Board stated that it would permit a minimum replacement of fluids withdrawn by injected water of 80 per cent to allow the testing of wells for flood response but in any case would require a replacement by injected water and gas of at least 100 per cent. An annual review hearing was not held during the year 1969 and the same replacement requirements for the period July 1, 1968 to June 30, 1969 were continued for the period July 1, 1969 to June 30, 1970.

At the hearing held on September 17, 1970, the following matters were considered:

(a) The progress and performance of each pressure maintenance program,

(b) The level of replacement of gross fluids withdrawn by water injection for the period July 1, 1970 to June 30, 1971.

(c) Special consideration of the voidage incurred by the testing of high gas-oil ratio wells in Units 4, 5 and 6.

(d) The need for future review hearings.

(e) The change of the Tract Agent of Owner of Tract 17 in Unit 3 and the change in address of the Tract Agent of Owner of Tract 438 in Unit 6. The Board decided that it could not consider these matters at the hearing because the changes were not included in the notice of hearing for this proceeding. The requested changes were subsequently considered at a hearing held on October 19, 1970.

SUBMISSION OF THE OPERATORS

Western Decalta - Turner Valley Units 3 and 4

Progress and Performance

A summary of oil rate, gas-oil ratio and water-oil ratio for each unit as reported by Western Decalta is shown in Table 1:

TABLE 1

Operating Year July 1 - June 30	Oil Rate Bbl/day	GOR Cu ft/Bbl	WOR Bbl/Bbl
Unit 3			
1968 - 1969	489	3975	1.096
1969 - 1970	512	3417	1.175
Unit 4			
1968 - 1969	606	3015	0.268
1969 - 1970	719	3872	0.438

The decline in the withdrawal rate as a result of lower gas-oil ratios has permitted lower injection rates into selected injection wells in order to minimize water breakthrough. The gas-oil ratio for Unit 4 has increased over the past year as a result of gas breakthrough in Part II of the unit. The gas-oil ratio in Part I has remained constant.

Encouraging oil response was noted in the southern part of Unit 3 which appears to be approaching fill up. Fill up is defined as occurring when the free gas saturation, which existed at the start of water flood and estimated to be about 30 per cent of pore volume, is replaced by injected water. Western Decalta estimated that fill up in the central portion of the units should occur in about four years. Fill up is probably occurring in the down-dip side of the reservoir in localized regions near the injection wells.

Western Decalta stated that it has discontinued using gas an an artifical lifting device in Unit 3. The gas lift system was considered inefficient and inadequate at wells which have back flooding tendencies. Artifical lift is now by rod type pumping units which creates enough drawn-down at the producing well to allow both porous zones to be flooded.

Western Decalta expressed the opinion that the schemes in both units are progressing in the best possible economic way. It could see no advantage to accelerating the time to achieve fill up by reducing the withdrawal rate.

Replacement Objective

In Unit 3, 157 per cent and 160 per cent of the withdrawals were replaced by injected water for the 1968 -1969 and 1969-1970 operating years respectively. No gas was injected to the unit during these periods. In Part I of Unit 4, 154 per cent and 157 per cent of the withdrawals were replaced by injected water for the 1968-1969 and 1969-1970 periods respectively. No gas was injected to this part. In Part II, 34 per cent of the withdrawals were replaced by injected water and 174 per cent replaced by injected water and gas during 1968-1969 and 13 per cent of the withdrawals by injected water and 97 per cent by injected water and gas during 1969-1970.

Western Decalta requested that the level of replacement of gross fluids withdrawn by water injection be continued at 100 per cent for the period July 1, 1970 to June 30, 1971 for Unit 3 and Part I of Unit 4. It stated that it intends to continue to exceed the recommended level of replacement as has been accomplished in previous years. Western Decalta further requested that the Part II of Unit 4 be continued to be operated in accordance with good engineering practice.

Well Testing

Western Decalta stated there are no high gas-oil ratio wells in Unit 3 but that there are two or three wells in Unit 4 that produce at a high gas rate. While there is no problem in replacing the gross withdrawals by injected water,

Western Decalta stated that it would prefer to have a flexibility of 10 to 20 per cent on the replacement requirement in the event of equipment failure or sudden decline in injection rates.

Future Review Hearings

Western Decalta did not believe future reviews on a yearly basis would be necessary but that future hearings should be called at the Board's discretion.

Royalite - Turner Valley Unit 5

Progress and Performance

Since the last review of this unit, nine wells have been converted to water injection service and additional wells are scheduled for conversion during the next year. The injection rate was maintained in excess of 16,000 barrels of water per day whereas the high pressure pump capacity is about 20,000 barrels per day. Gulf stated that it would not be practical to increase the injection pump capacity beyond this rate. The gas-oil ratios in the unit are declining and over injection should be accomplished by the end of the year. Gulf contended that in view of the low fluid producing capacity of most wells in Unit 5 it would not be possible to accelerate the response by either increasing the injection rates by further injection well conversions or shutting in of wells to achieve earlier fill-up. It cannot justify foregoing production now in order to obtain some additonal oil 10 to 15 years from now. Gulf said it intends to create water fences across the pool by converting wells to water injection service as they flood out where performance demonstrates that a water fence can be developed. From an economic standpoint it would not be desirable to convert a good producer to an injection well in order to create the fence.

The increase in oil rate and decline in gas-oil ratio for the unit is shown on Table 2 below:

TABLE 2

Operating Year July 1 - June 30	Oil Rate Bbl/day	GOR Cu ft/Bbl	WOR Bbl/Bbl
1968 - 1969	806	6082	0.076
1969 - 1970	862	5618	0.068

The increase in oil rate is due, in part, to the improvement in lift efficiency at wells which have responded to the flood. Gulf intends to change from gas lift operations to pumping operations wherever the oil production rate economically justifies the change.

The replacement ratio in the central part of the unit is somewhat below unity. This area of the reservoir is of poor rock quality.

Replacement Objective

During the 1968-1969 year, 87.8 per cent of the gross withdrawals were replaced by injected water and 104.7 per cent by injected gas and water. During the 1969-1970 year, 83.9 per cent of the withdrawals were replaced by water and 103.3 per cent by gas and water. Gulf stated that the unit will have sufficient capability to replace all of the fluids withdrawn by injected water during the next year.

Well Testing

Gulf stated that the testing of high gas-oil ratio wells has permitted the operator to direct the flood front movement in some areas. While the water injection rate will be sufficient to replace all fluids withdrawn, Gulf requested that a 5 per cent allowance for replacement of test production by gas injection be granted for the next period to allow for unforeseen mechanical problems.

Future Review Hearings

Gulf stated that the past hearings have served a useful purpose and that future hearings should be held at the discretion of the Board. It expressed the opinion that a hearing more frequently than every two years would not be necessary.

Home - Turner Valley Unit 6

Progress and Performance

A review of the operation of the Unit over the last ten years indicates that the oil rate has dropped from an average of 1281 barrels per day to 870 barrels per day in the current year while the gas-oil ratio decreased from 15,739 cu ft per bbl in 1960 to less than 5,000 cu ft per bbl in the first half of 1970. The unit has produced 88.6 per cent of the oil estimated to be recoverable under primary depletion which would have taken to the year 2000 to produce. The rate of gross reservoir withdrawals was averaging about 28.5 million reservoir barrels per year prior to 1960 and has been reduced to less than 8 million reservoir barrels per year since 1967. The wells converted to water injection represents 33.8 per cent of the effective productivity of the unit. A summary of the average oil rate gas-oil ratio and water-oil ratio for the past two years is shown on Table 3 below:

TABLE 3

Operating Year July 1 - June 30	Oil Rate Bbl/day	GOR Cu ft/Bbl	WOR Bbl/Bbl
1968 - 1969	898	7285	0.172
1969 - 1970	869	6377	0.237

Home stated that the basic problems of low production rates, early flood out of producers and the high cost of artifical lift continues to be matters of much conern to the unit operator. It expressed the opinion that water flowing through fractures is the main reason for early flood out of wells which offset injectors and as a result the matrix porosity is not being efficiently flooded other than by the imbibition process which is too slow to benefit the current operation.

Home stated that the injection is distributed reasonably well over the unit and the replacement ratio is greater than one in all areas. Some isolated areas have a replacement ratio of near 5 but the response has not been commensurately better than in other areas. Furthermore, the injection and production history does not appear adequate to estimate future behaviour by extrapolation.

Home stated that the injection rate is about 30,000 barrels of water per day and the unit has no plans to increase this injection capacity. When the gas-oil ratios have been controlled the replacement ratio should be about 2. Gas will only be injected in the event of equipment failure and gas plant shut downs.

Replacement Objective

During the year 1968-1969, 106.23 per cent of the gross withdrawals were replaced by injected water and 108.29 per cent by injected gas and water. During the year 1969-1970, 121.02 per cent of the gross withdrawals were replaced by injected water and 122.05 per cent by gas and water. Home requested that the same replacement requirements as for the previous year be continued.

Well Testing

Home stated that the unit would inject gas if it was not possible to replace by water injection. Home requested that the same credit for gas injected applied in the previous year be continued.

Future Review Hearings

Home stated that the past hearings have served a useful purpose and that future hearings should be held at the discretion of the Board.

SUBMISSION OF INTERVENERS

Gulf, Home and Western Decalta supported one anothers submission. The Department of Mines and Minerals indicated in its letter dated July 17, 1970, that it would not be represented at the hearing.

VIEWS OF THE BOARD

Progress and Performance

The Board notes that significant progress has been made by the operators of the oil units to reach the objective of full replacement of gross withdrawals by water injection. While there have been some encouraging increases in oil production rates and decreases in gas-oil ratio, the Board continues to share with the operators concern regarding the early breakthrough in some wells. The Board is of the opinion that, based on past performance, achieving fill up of the initial gas saturation is desirable in most parts of the pool. The Board believes that the operators should continue to maximize water injection to achieve this condition and that each operator should study the performance of his unit to determine the areas where best advantage may be achieved by accelerating water injection.

Replacement Objective and Well Testing

The Board agrees with the operators that there is some need to test wells for response and believes that a relaxed replacement requirement should be permitted to allow for such testing.

The Board believes that the objective for Units No. 3, 5, 6 and Part I Unit 4 should continue to be at least 100 per cent voidage replacement by water. However, where testing of wells for response is desirable, the Board believes that the replacement of gross withdrawals by injected should not be permitted to fall below 90 per cent. The Board believes that Part II of Unit 4 should continue to operate in accordance with good engineering practice.

Future Review Hearings

The Board agrees with the operators that the past hearings have been useful. It believes that hearings need not be held on a regular basis but that future hearings should be held at the request of the Board or of any interested person.

DECISION

The Board after considering the evidence presented at the hearing decides as follows:

1. For the period July 1, 1970 to June 30, 1971 and for each later twelve month period commencing July 1, at least 100 per cent of the volume of fluids withdrawn from each of Unit No. 3, 5, 6 and Part I of Unit No. 4, shall be replaced by water injection. The Board will allow the testing for flood response of wells near the flood fronts and will exempt the volume of fluids produced from the test from the aforementioned replacement requirement provided that the exclusion of such volumes would not result in a replacement by injected water of less than 90 per cent of withdrawals, and a replacement by injected water and gas of less than 100 per cent. Part II of Unit 4 shall continue to operate in accordance with good engineering practice.

2. Further review hearings shall not be held on a regular basis but will be held at the request of the Board or any interested person.

The necessary amendment to Board Order No. TVU 3, Order No. TVU 4, Order No. TVU 5 and Order No. TVU 6 to give effect to the Board's decision will be issued forthwith.

OIL AND GAS CONSERVATION BOARD

Vernon Millard
Vernon Millard
Board Member

DATED at Calgary, Alberta
December 10, 1970

OIL AND GAS CONSERVATION BOARD

Decision 71-1
Application No. 5382

APPROVAL NO. 1153
WAINWRIGHT WAINWRIGHT POOL

THE APPLICATION AND HEARING

Bailey Selburn Oil & Gas Ltd., as operator of Wainwright Project No. 4, applied to the Board for amendment of Approval No. 1153 which authorizes its enhanced recovery operations in the Project, by

(a) rescinding clause 4 and clause 5, subclauses (1) to (5),

(b) substituting a new clause that would require that net withdrawals, on a quarterly basis, will not occur in the project on and after October 1, 1970, and will not occur in well patterns 2, 4 and 8 and in proposed pattern 9, and

(c) establishing well pattern 9 which would include parts of present patterns 4 and 8.

The application was heard by the Board on December 15, 1970, with Mr. Vernon Millard and Mr. D. R. Craig, P. Eng., sitting.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Bailey Selburn Oil & Gas Ltd.	J. Pawelek, P. Eng. D. Kestevan, P. Eng.	Baysel
Piute Petroleums Limited	J. M. Fulton, P. Eng. (of Fulton Engineering Limited)	Piute
Board Staff	D. N. Blades, P. Eng. T. R. Barrows, E.I.T.	Board Staff

BACKGROUND

Following the Board initiated hearing held in December 1968, Decision 69-5 was issued in which the Board concluded that a pressure sink had been created within Project No. 4 and that

there had been fluid migration from Project No. 3 to Project No. 4. Corrective measures which included a 400 pounds per square inch gauge (psig) pressure stipulation for each producing well in Project No. 4, replacement of withdrawals in the area offsetting Project No. 3 and semi-annual pressure determinations and performance reporting were incorporated in Approval No. 1153 which rescinded the original Approval No. 821. In November 1969, the Board heard an application by Baysel requesting deferrment of the 400 psig pressure requirement date from December 31, 1969 to September 30, 1970, and approval of the conversion of well Nuco Baysel Wainwr 15D-35-45-6 to injection. By Decision 70-1, the Board granted both parts of the application. In September 1970, the pressure requirement date was deferred until October 31, 1970, so that pressure data recorded during September could be analysed. The October 31, 1970, date was extended by the Board to December 31, 1970.

ISSUES

The Board considered the issues to be as follows:

1. Reservoir Pressure Level

2. Voidage Replacement Performance

3. Correlative Rights

RESERVOIR PRESSURE LEVEL

(1) Views of Baysel

Baysel stated its analysis of pressure behavior in five Wainwright projects during the period from 1963 to 1970 showed that individual well pressures could not be consistently maintained above the 400 psig pressure level even with several years of over-injection. In support of its statement, Baysel pointed out that large pressure variations were experienced at individual wells between surveys and that no one well in the projects exhibited a consistent pressure trend.

Baysel submitted that 27 per cent of the capable wells in the projects were currently experiencing pressures in excess of 400 psig and of these the majority were side wells located within nine-spot flood patterns. It noted that corner wells were maintained at a constant or gradually increasing pressure over a period of years and that those wells outside an inverted nine-spot flood pattern were not significantly affected by the flood. In its review Baysel noted that severe foaming conditions were apparent from the existence of changing pressures and corresponding fluid levels within a 24- to 48-hour period and by fluid gradients in the order of .34 psig per foot. Consequently, Baysel concluded that several of the high pressures recorded were erroneous. No attempt was made to qualify any specific pressure determination.

Baysel noted that well pressures in Project Nos. 1, 2 and 4, which represent 80 per cent of all the wells considered in its submission, have recently demonstrated either stabilization or a very gradual decline despite consistent over-injection. In light of this and preceeding conclusions, Baysel feels that it is unreasonable to retain the 400 psig clause within Approval No. 1153.

(2) Views of Piute

Piute submitted that the pressure clause of Approval No. 1153 should be retained as an additional control on the performance of Project No. 4. It contended that calculated pressures determined from acoustical well sounder surveys are substantially higher than pressures recorded by bottom hole pressure gauges and by drill stem tests and that the 400 psig pressure requirement is necessary to ensure a satisfactory pressure level in the reservoir. Piute agreed with Baysel that the Project No. 4 pressure has tended to stabilize during the past few years.

(3) Views of the Board

The pressure performance of Project No. 4 since the November 1969 hearing, based on Baysel's figures and summarized below, indicates that the pressure decline observed previously in this project has been checked and that the producing well pressures have made significant advances toward the required 400 psig pressure level. The Board considers the pressures representative and the trend reliable.

Year	Quarter	Project Arithmetic Average Pressure
1969	July to September	324
1969	October to December	302
1970	January to March	341
1970	April to June	342
1970	July to September	363

The Board feels that Baysel has made a reasonable effort to attain the required pressure level of 400 psig. However, it notes that the net withdrawals determined by the Board in Decision 69-5 have not been replaced and accordingly a return to the 1966 pressure level is not likely to occur unless this is accomplished. Nevertheless, the Board recognizes that only substantial additional over-injection would provide for the return of the current project pressure to the 1966 level.

Performance suggests that such over-injection might result in aggravated water breakthrough if achieved through the current injectors. The Board feels that under the present circumstances, maintenance of the reservoir pressure in the project at the December 1970 level is satisfactory but that pressure performance should continue to be monitored to check calculations. It follows that the kind of pressure survey required by clause 5, subclause 4 of the Approval should be retained, although the Board believes that future pressure monitoring on the basis of average pattern and project pressures rather that individual well pressures should be satisfactory.

VOIDAGE REPLACEMENT PERFORMANCE

(1) Views of Baysel

Baysel submitted that severe water breakthrough has occurred in well patterns 1, 4, 5 and 6, and that two wells in pattern 5 were shut in when they watered out to below the economic limit. The economic limit for a well was estimated by Baysel at 5 barrels of oil per day with a water cut of 95 per cent. Also, an oil productivity decline has been experienced in all four well patterns since the initiation of higher injection rates in March and April 1970. Baysel feels that the producing life of several wells, estimated from individual productivity decline curves, has been shortened substantially as a result of the increased injection rates. It concluded that increased injection rates will not result in higher ultimate recovery from the pool.

Baysel was unable to say if the declining performance of the project could be attributed to normal flood out expectations or to other causes.

Baysel noted that maximum net voidage occurred in June 1968 and that a cumulative net voidage replacement ratio of 1.0, based on its calculations, was reached in mid-September 1970. It proposed to maintain this status by replacing withdrawals on a quarterly basis for the project. Baysel submitted that a three-month replacement interval will offer the necessary operating flexibility required to periodically test the wells currently shut in due to high producing gas-oil ratios.

Baysels request for the establishment of new well pattern number 9 was to accomodate the new injection well in tract 15D of Section 35, Township 45, Range 6, West of the 4th Meridian.

(2) Views of Piute

Piute, in commenting on replacement of withdrawals within Project No. 4, made reference to the pressure data and suggested that calculations based on sonic pressures would

always result in a lower than actual reservoir voidage. This, it submitted, would be evidenced in successive years by reservoir pressure declines despite calculated replacement ratios exceeding 1.0.

Furthermore, Piute contended that the weighted reservoir pressure within Project No. 4 should be, but is not, approximately the same as the original project pressure if the cumulative replacement ratio was equal to or in excess of 1.0. It concluded, therefore, that the net cumulative replacement was not positive as stated by Baysel in its application.

Piute felt that the proposed injection pattern number 9 was satisfactory if treated similarly to patterns 2, 4 and 8.

(3) Views of the Board

In reviewing the operations of Project No. 4 during the interval from November 1969 to September 1970, the Board noted that quarterly replacement ratios for Project No. 4 as calculated by Baysel exceeded 1.0 at all times. The Board observed also that fresh water injection had increased by approximately 20 per cent during this interval and that quarterly replacement ratios in patterns 2, 4 and 8 have been maintained at a level satisfactory to the Board. The performance of the project is illustrated in the following table.

Year	Quarter	Project Replacement Ratio	
		Baysel	Board
1969	October to December	1.143	1.195
1970	January to March	1.053	1.016
1970	April to June	1.344	1.280
1970	July to September	1.418	1.373

Although the Board agreed that the replacement ratios are in excess of 1.0, it considers the replacement calculated by Baysel to be somewhat optimistic due to the relatively high solution gas figure used in the calculations. The Board believes that the PVT analysis from the Bell #15-D-32 well is more representative of fluid properties in the Wainwright Wainwright Pool and hence, will continue to use the PVT data for that well in appraising the performance of Project No. 4.

With regard to water breakthrough experienced by several wells within Project No. 4, the Board is not convinced that increased injection rates are entirely responsible for the increase in water production and the decline in oil productivity.

It noted that water cut performance for the project has steadily risen since 1965, suggesting that a continuing increase in water production should have been anticipated. In addition, the Board believes that water breakthrough could have been expected on the basis of the volumes of water injected into the patterns. However, in view of recent performance, the Board believes that caution should be exercised with regard to the level of water injection.

The Board concurs with the need for establishing the new pattern number 9.

CORRELATIVE RIGHTS

(1) Views of Baysel

In an effort to protect correlative rights between Project Nos. 3 and 4, Baysel proposed to continue injection in patterns 2, 4 and 8 (and 9 if approved) at rates sufficient to ensure that no net withdrawals occur on a quarterly basis in those patterns.

(2) Views of Piute

Piute submitted that retention of the pressure clause within the approval is essential to protect correlative rights between Project Nos. 3 and 4. Piute compared the high production rate of Project No. 4 well Nuco Baysel Wainwright 15B-35-45-6 and the low production rate of Project No. 3 well Piute Wainwright 2B-2-46-6, and stated that this supports the contention that the fluid drainage tends in the direction of the pressure sink and that this pressure sink is still established inside Project No. 4.

(3) Views of the Board

The Board is satisfied that in the last 12 to 15 months correlative rights have been maintained and that the operation of Project No. 4 has not had an adverse effect on the performance of Project No. 3. The Board believes that this status will be continued if voidage is replaced and the current pressure is maintained in patterns 2, 4 and 8 and the proposed pattern 9.

DECISION

The Board has decided to amend Approval No. 1153 to:

1. provide for the replacement of withdrawals in the project and patterns 2, 4, 8 and 9 on a quarterly basis,

2. permit the establishment of the proposed injection pattern 9, and

3. require

   (a) the average pressure, in the project and patterns 2, 4, 8 and 9, determined in a manner satisfactory to the Board, be maintained at the current level,

   (b) pressure surveys at six-month intervals, and

   (c) semi-annual reporting of the projects performance commencing December 31, 1970, and continuing for a period of two years, and thereafter annual reporting.

The Board has decided to discontinue the pressure requirement clause on an individual well basis. An amendment of the subject approval to give effect to this decision will be issued.

OIL AND GAS CONSERVATION BOARD

Vernon Millard

Vernon Millard
Board Member

DATED at Calgary, Alberta
January 20, 1971

OIL AND GAS CONSERVATION BOARD

Decision 71-2
Application No. 5132

INTEGRATED SCHEME FOR ENHANCED RECOVERY IN CERTAIN POOLS IN THE VIRGO FIELD AND THE ZAMA FIELD

THE APPLICATION AND HEARING

Imperial Oil Limited applied under section 38 of The Oil and Gas Conservation Act, 1969, for approval of a scheme for enhanced recovery of oil in the following pools:

Virgo Keg River B Pool
Virgo Keg River D Pool
Virgo Keg River E Pool
Virgo Keg River H Pool
Virgo Keg River J Pool
Virgo Keg River K Pool
Virgo Keg River N Pool
Virgo Keg River O Pool
Virgo Keg River P Pool
Virgo Keg River S Pool
Virgo Keg River NN Pool
Virgo Keg River OO Pool
Virgo Keg River CCC Pool
Virgo Keg River DDD Pool
Zama Muskeg Y Pool.

Imperial Oil Limited proposed that the pools be depleted in a partially sequential manner and that water flood would be applied in all the pools.

The applicant also applied under section 34, subsection (2) of The Oil and Gas Conservation Act, 1969, for the fixing of a single aggregate amount of crude oil or condensate that may be produced from the above named pools or any of them, regardless of whether all of the pools would be producing pools during the proration period for which the oil allocation is made.

The matter of ultimate reserves for each of the pools was considered at the hearing.

The application was heard on September 29, 1970, by the Board with G. W. Govier, P. Eng., A. F. Manyluk, P. Eng. and V. Millard sitting.

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Imperial Oil Limited	D. Towson, P. Eng. J. Pickel H. Kimmel	Imperial
Gulf Oil Canada Limited	T. E. Randall, P. Eng. R. V. Lang	Gulf
Hudson's Bay Oil and Gas Company Limited	M. D. Field T. H. Renner G. L. Cox	Hudson's Bay
Board Staff	R. O'Brien, P. Geol. G. H. Stafford, P. Geol. D. G. Pearson, P. Eng.	

DEFINITION OF THE ISSUES INVOLVED

The issues involved in the application are:

Relating to the aggregate allowable applied for under section 34, subsection (2) of The Oil and Gas Conservation Act, 1969,

1. the conservation advantages of the proposed integrated scheme,

2. the undertaking of the operators, and

3. the reliability with which the ultimate reserves may be estimated.

Relating to the approval applied for under section 38 of The Oil and Gas Conservation Act, 1969,

4. the suitability of the proposed enhanced recovery operation in each of the pools.

These issues require an appraisal of each of the proposed pools. The appraisal is dealt with first under the headings

(a) reservoir description,

(b) oil in place,

(c) recovery factors,

(d) scheme monitoring,

(e) interpool communication, and

(f) recognition of enhanced recovery.

RESERVOIR DESCRIPTION

The main issue pertaining to Imperial's reef model is the lateral extent of the effective reservoir pay in the Zama Member. A lesser issue pertains to the height of the lower anhydrite on the reef flanks.

Views of Imperial. Imperial had previously submitted its Keg River reef model(1) to the Board and it is shown on Figure 1. Its model was also discussed in Oil and Gas Conservation Board Decision 70-7(2). In summary, Imperial's model was initially developed using the data from 60 wells in the Virgo-Zama basin available to it at the time of the original study, and later confirmed with data from another 60 flank wells. Using all available wells and data in developing the model, Imperial's main conclusions were:

1. Differential subsidence in the "Zama sub-basin" caused Keg River pinnacles of varying thicknesses, which grew to a common elevation.

2. The Zama anhydrite was deposited up to the level of the Keg River reef crests.

3. The Zama member reservoir becomes ineffective about 600 feet from the crest edge, as defined by the geological model.

4. The reef crest roll-off point and lateral extent of the effective Zama pay cannot be determined from seismic information alone.

Views of the Board Staff. The Board staff, in its intervention, submitted that Imperial overestimated the reserves in the Zama member because it extended the full crestal Zama pay to 600 feet from the Keg River reef crest edge.

The Board staff submitted that the extent of the Zama reservoir in the flank position is better determined from whipstocked wells and dual well reefs. In the opinion of the Board staff, penetration of the Zama member, the underlying anhydrite and the Keg River reef in the original hole, and of the Keg River reef crest in the whipstocked hole are required to estimate the lateral extent of the Zama reservoir. Eight cases from 23 whipstocked wells and three cases from five dual-well reefs were available and used by the Board staff to establish that the effective Zama pay does not extend substantially beyond 400 feet from the Keg River reef crest edge.

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(1) Imperial Oil Limited, Proceeding No. 4865 - Annual Reserves Hearing, Virgo Keg River C Pool, January 19, 1970.

(2) Decision 70-7, Application No. 5065, Integrated Scheme for Enhanced Recovery in Zama and Virgo Pools, By Solvent Bank Flood, Gas Flood and Water Flood.

Gulf and Hudson's Bay questioned the Board staff use of whipstocked wells and dual well reefs in determining the lateral extent of the Zama reservoir in the reef flank position. Hudson's Bay expressed doubt that the small number of whipstocked wells and dual well reefs used by the Board staff to determine Zama porosity limits would be representative of the Zama and Virgo pools.

In response to the Board staff intervention, Imperial stated that, of the wells used in its model, only five wells were located between 400 and 600 feet off-crest. Of this number, only one well indicated an effective reservoir in the Zama member thus indicating some merit to the Board staff's contention.

Views of the Board. The Board has reviewed the Imperial model specifically regarding the following points: the distance that effective Zama reservoir extends beyond the crestal area, and the height of the lower anhydrite on the reef flanks.

Since no new evidence was presented by Imperial at the hearing, the Board can see no basis for changing its views presented in Decision 70-7, respecting its Virgo-Zama reef model. Imperial did not seriously contest the Board staff argument concerning determination of the limits of the Zama reservoir. Therefore, based on the available data from whipstocked wells and dual well reefs, the Board concluded that 400 feet is a reasonable distance to expect the effective Zama reservoir to extend from the reef crest. These data also indicated that the Zama thickness and porosity deteriorate in the off-reef areas in an unpredictable manner. For calculation purposes, however, the Board considers that the 400 foot tapered Zama extension is approximately equivalent to a lateral extension of the well-bore thickness and porosity of the Zama member for a distance of 200 feet from the crest.

With respect to the height of the lower anhydrite relative to the reef crest, the Board believes that the distance below the flat or crestal part of the reef to the anhydrite cannot be determined with accuracy and that the lower anhydrite occurs some 20 feet below the reef crest.

OIL IN PLACE

Views of Imperial. Imperial determined the rock volume for each pool by volumetric means using the geological model developed by it for the Zama type reef. The crestal area for each pool was estimated from seismic data using the procedure outlined in a submission respecting Virgo Keg River C Pool.

Imperial calculated an average porosity for each pool using well bore core analysis and sidewall neutron logs. It expressed the opinion that individual well bore derived porosity values are more representative of the porosity for individual pools than a composite derived porosity.

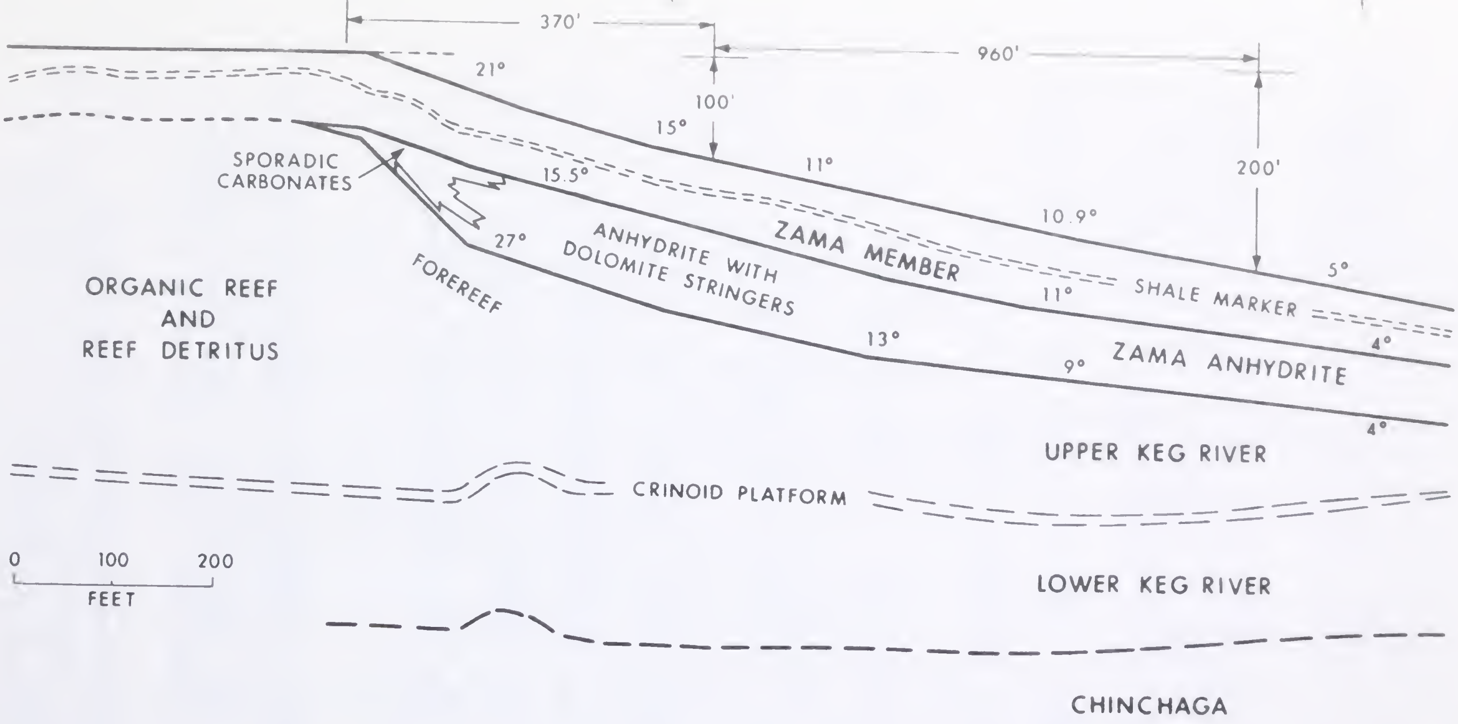

FIGURE 1

IMPERIAL REEF MODEL

AFTER FIGURE 2 OF PROCEEDING NO. 4865, ANNUAL RESERVES HEARING, VIRGO KEG RIVER C POOL, JANUARY 19, 1970

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA FEBRUARY, 1971

Imperial developed a porosity-connate water saturation correlation of ØSw = 59 from oil base core data from the Rainbow Keg River K Pool. The water saturation determined for each pool from this correlation was adjusted to account for a 20-foot transition zone having a connate water saturation of 35 per cent.

Imperial performed material balance calculations for each pool but expressed the opinion that "there is considerable uncertainty about the validity of oil-in-place values calculated by material balance because of the inter-pool communication known to exist in this area." Imperial therefore used the volumetric method exclusively to determine the oil in place for the pools in the proposed scheme.

Views of the Board. Having regard for the decision respecting the reservoir model, the Board calculated the oil in place for each pool using both the volumetric and material balance calculation techniques. For the volumetric estimate the Board determined the crestal area from seismic information having regard for the largest isochron values recorded from the seismic data. Assuming an equivalent circular area, the rock volume of the pool was determined by employing the Board's previously described model. The oil in place was then calculated using the average well bore porosity, connate water saturation as described previously and hydrocarbon fluid properties for each pool. The oil in place so obtained was increased by three per cent to account for the additional oil which would result if a 400-foot Zama extension with decreasing porosity was used rather than a 200-foot Zama extension with constant porosity.

Notwithstanding Imperial's position respecting material balance calculations, the Board believes that where the interference effects are not significant, these calculations can be useful. The Board found undersaturated or saturated material balance calculations useful in estimating oil in place values for three of the pools.

Table 1 compares the reservoir parameters and the oil in place values as submitted by Imperial and set by the Board.

RECOVERY FACTORS

Views of Imperial.

Primary Depletion. Imperial made a number of representative reservoir depletion studies using a two-dimensional mathematical model based on a composite geological model containing variable porosity and permeability. The studies indicated that the recovery factor varied from 45 per cent in a large reef, where most of the oil in place is in the central core, to as low as five per cent in a small reef where most of the oil is in the Zama member. The recovery factor for the individual pools in the scheme was calculated using

the constant porosity indicated from the well bore data for each pool and the procedure outlined in Imperial's reserve submission to the Board for the Virgo Keg River C Pool. Imperial adopted, in its recovery calculations, a residual oil saturation of 30 per cent of pore volume based on special core tests on samples from the Zama Field. A 40-foot sandwich zone thickness was used above the oil-water contact for each pool. This includes 15 feet for the degree of conformance and 25 feet to account for coning of gas and water. The final sandwich zone was positioned in the reservoir having regard for the amount of water influx in each pool. Imperial stated that the predicted recovery from the pool would not be greatly affected by assuming a constant reef porosity rather than a variable porosity as indicated from the geological model.

Imperial stated that the actual pool performance in some pools has indicated that the recovery by primary depletion would be greater in some pools than that predicted by the two-dimensional mathematical model study. Imperial expressed the opinion that the higher recoveries would result from the effect of the aquifer which was not considered in its original study of the primary depletion mechanism. The individual pool primary recovery factors are shown in Table 2.

Gas Flood. Imperial used the same approach to determine the gas flood recovery factors as was used to determine the primary recovery factors. The average recovery factor for the pools in the scheme was calculated to be 24 per cent. The recovery factors for the proposed pools are shown in Table 2.

Water Flood. The water flood recovery factors were calculated using a two-dimensional mathematical model simulator based on a composite geological model and a procedure similar to that outlined for the Virgo Keg River C Pool. Imperial assumed a sandwich thickness of 30 feet at the top of the pool in its recovery calculations. This loss includes a 20-foot thickness due to water coning and a 10-foot thickness which accounts for the degree of conformance of the displacement mechanism. The volume of oil in each pool above the point of well penetration was assumed to be unrecoverable. Imperial adopted a conformance factor of 100 per cent in the "central core" region. The water flood recovery factors for each pool in the proposed scheme are shown in Table 2. The volumetrically weighted average recovery factor was calculated to be 47 per cent.

Solvent Flood. Imperial calculated solvent flood recovery factors for all the pools in the scheme except for the Zama Muskeg Y Pool which Imperial stated cannot be solvent flooded. Using a sandwich zone thickness of 35 feet at the original oil-water contact and assuming no recovery of the oil in the Zama member below the Zama anhydrite spill point the

recovery factors as shown on Table 2 were calculated. An average volumetrically weighted recovery factor of 49.5 per cent was calculated for the pools that could be solvent flooded.

<u>Views of Hudson's Bay</u>. Hudson's Bay made an independent water coning study for different crestal radii using a two-phase radial model and the reservoir characteristics and the fluid properties determined by Imperial for its geological model. Hudson's Bay's study indicated that the water flood recovery factors based on the proposed production schedule would be lower than those proposed by Imperial. Hudson's Bay stated that at the proposed production rates severe water coning would occur resulting in low recoveries by water flooding. It also stated that "water cones, once developed, require long periods of time in order to sufficiently heal." Hudson's Bay contended that "if the well is located eccentrically in relation to an anhydrite-free crest the sweep efficiency of the Zama member will be lower than that for the case of a centrally located wellbore". It stated that, as the method of calculating the crestal radius and the positioning of a well in relation to the Zama anhydrite are not sufficiently accurate, the water flood recovery factors calculated by Imperial should be modified to account for the eccentric location of a well within a reef. Hudson's Bay did not present any recovery factors for the pools in the proposed scheme.

<u>Views of Gulf</u>. Gulf stated that it supported the principle of an integrated scheme for water flood of a group of communicating single well pools by injection into a single pool. It contended that simultaneous oil production and water injection at a well would cause increases in water cone heights resulting in reduced ultimate oil recoveries from the wells designated as injectors.

<u>Views of the Board</u>. The Board believes that the recovery will be affected by the quality of the reef and, having regard for possible reservoir flow barriers, has adopted a conformance factor of 90 per cent for all pools. Regarding Hudson's Bay's contention that the recovery factor for a pool that has a well completed eccentrically would be lower than if the well were completed in the centre of the pools, the Board believes that the effect on recovery would be difficult to quantify and that the change in recovery would not be significant.

There being no new evidence respecting residual oil saturation, the Board used its previously adopted residual oil saturation of 38 per cent of pore volume, which includes a three per cent of pore volume loss due to viscous effects, in the calculation of the recovery factor for primary depletion.

A residual oil saturation of 35 per cent of pore volume was used for the water flood case. These figures are based on residual oil saturation data from all available Keg River reef core samples. The Board adopted a residual oil saturation after solvent flood of two per cent of pore volume to account for possible losses in the dead-end pore spaces.

Primary Depletion. The Board estimated, on the basis of an economic producing limit of 15 barrels of oil per well per day, sandwich zone thicknesses ranging from 20 feet to 35 feet positioned just above the original oil-water contact. The Board believes that some oil will be recovered by fluid expansion from the Zama member below the lower anhydrite spill point, and in its calculation has estimated that this would amount to four per cent of the oil below the spill point. The resulting primary recovery factor was decreased by two percentage points to account for the additional oil losses had the 400-foot Zama extension with decreasing porosity been used in the model instead of the 200-foot Zama extension with constant porosity. Table 2 shows the primary recovery factors as calculated by the Board.

Water Flood. The Board estimated the water flood recovery factors for all the pools in the proposed scheme using an oil sandwich zone thickness of 15 feet at a terminal producing rate of 10 barrels of oil per day per well. The oil zone above the well penetration in case of flank wells was considered unrecoverable. The Board estimated from its two-phase radial model study that about 30 per cent of the oil in the Zama member below the lower anhydrite spill point would be recovered under the water flood mechanism. Table 2 shows the water flood recovery factors as calculated by the Board.

Solvent Flood. For the solvent flood mechanism an oil sandwich zone of 20 feet was estimated by the Board at a terminal oil production rate of 10 barrels per day per well. An ultimate recovery factor for each pool was calculated assuming no recovery below the lower anhydrite spill point, a residual oil saturation of two per cent pore volume in the miscibly swept region. The Board assumed that a secondary gas cap would be formed in each pool prior to the commencement of the solvent bank placement and as a result the recovery factors would be reduced by two percentage points.

The solvent flood recovery factor was decreased by three percentage points to account for the additional oil losses that would have occurred with a 400-foot Zama extension with decreasing porosity instead of the 200-foot Zama extension with constant porosity. Table 2 shows the solvent flood recovery factor for each pool in the proposed scheme as calculated by the Board.

The volumetrically weighted average solvent flood recovery factor for the whole scheme was calculated to be 68 per cent as compared with the volumetrically weighted average recovery factor of 49.5 per cent determined by Imperial. The difference between the two estimates is largely due to the difference in the geological model.

As discussed in the heading "reservoir description" the Board does not agree with Imperial's interpretation that the effective Zama pay in the reef flank extends to a distance of 600 feet from the reef crest. Imperial's model results in a larger volumetrically determined oil in place than the Board's model if the same crestal area is used in both volumetric estimates. Based on the Board's understanding of Imperial's calculation procedure, the incremental volume of oil recovered from the Zama wing by water flood over solvent flood is nearly equivalent, in most cases, to the incremental volume of oil recovered in the "central core" area by solvent flood over water flood. In view of the smaller Zama wing extension in the Board's model, the Board calculates a significantly greater recovery by solvent flood than by water flood.

The Board notes that Imperial, in calculating recovery factors for a specific pool, used a constant well bore porosity throughout the Zama wing instead of adopting a variable porosity as indicated by its geological model. The Board believes that this assumption would have the effect of increasing the recovery factor for water flood but decreasing the recovery factor for solvent flood due to more oil being assigned to the Zama wing than the geological model indicates.

The Board in its solvent flood recovery factor calculation has assumed that an additional well would be drilled in all pools where the existing well is located on the flank of the reef. In some cases such additional wells may not be economic.

SCHEME MONITORING

Views of Imperial. Imperial stated in a post hearing document dated November 16, 1970, that a semi-annual pressure survey would be taken of the pools in the proposed scheme for the first two years and thereafter on an annual basis unless experience should prove that other means of monitoring is required. If the pressure is less than the bubble point pressure for any given pool, the measurement frequency would revert to a semi-annual basis for that pool until the pressure increased above the bubble point pressure. Imperial stated that it is important to know when the oil-water contact reaches the top of the Keg River formation so that the production rate can be controlled while displacing oil from the Zama member. The level of the oil-water contact would be determined primarily by material balance calculations and confirmed on an irregular basis by using a neutron life-time log.

Views of the Board. The Board believes that pressure measurements should be taken on a semi-annual basis in accordance with the requirements of the Oil and Gas Conservation Regulations. It further believes it important that the oil-water interface of all pools in the proposed scheme be monitored to observe any interpool communications and the effectiveness of the proposed scheme. Oil-water interface measurements taken on a three year schedule would be appropriate.

The Board agrees with Imperial that the reservoir pressure in any group of pools should not be less than the bubble point pressure of the pool having the highest bubble point pressure in the group.

INTERPOOL COMMUNICATION

Views of Imperial. Imperial stated that interpool communication exists among pools in this area of the Virgo Field. The pools in the scheme are divided into the groups, as shown on Figure 2, on the basis of production performance and pressure history. Imperial agreed that communication could exist between the pools in the scheme and other operators' pools. Imperial said it would be prepared to enlarge its scheme from time to time to include its own pools outside the proposed scheme as dictated by performance and would also be willing to negotiate with other operators to include their pools in its scheme. Imperial stated that if there is pressure leakage to the surrounding pools outside the scheme, it would be prepared for some overinjection to compensate for this leakage. Each case would be evaluated separately as it occurs to determine if overinjection was feasible.

Imperial expressed the opinion that the large aquifer and the large number of pools which are interconnected through the aquifer made it impractical to run an interference test to evaluate interpool communication. It contended that the interference results would be inconclusive.

Views of Hudson's Bay. Hudson's Bay stated that "the degree and areal scope of the pressure interference effects are difficult to determine" and in some cases the interference effects may be negligible. It contended that, using the criteria proposed by Imperial, it is possible to show that a number of additional wells may also be in communication with the wells in the proposed scheme. Hudson's Bay expressed the opinion that in view of possible interference effects the water flood recovery factors should not be based on 100 per cent replacement of reservoir withdrawals by water injection. Hudson's Bay further stated that interference tests should be conducted to evaluate the degree of pressure communication between pools.

Views of the Board. The Board believes that there could be interpool communication to varying degrees between the pools within the scheme and between the pools in the proposed scheme and the pools outside the scheme. The Board agrees with

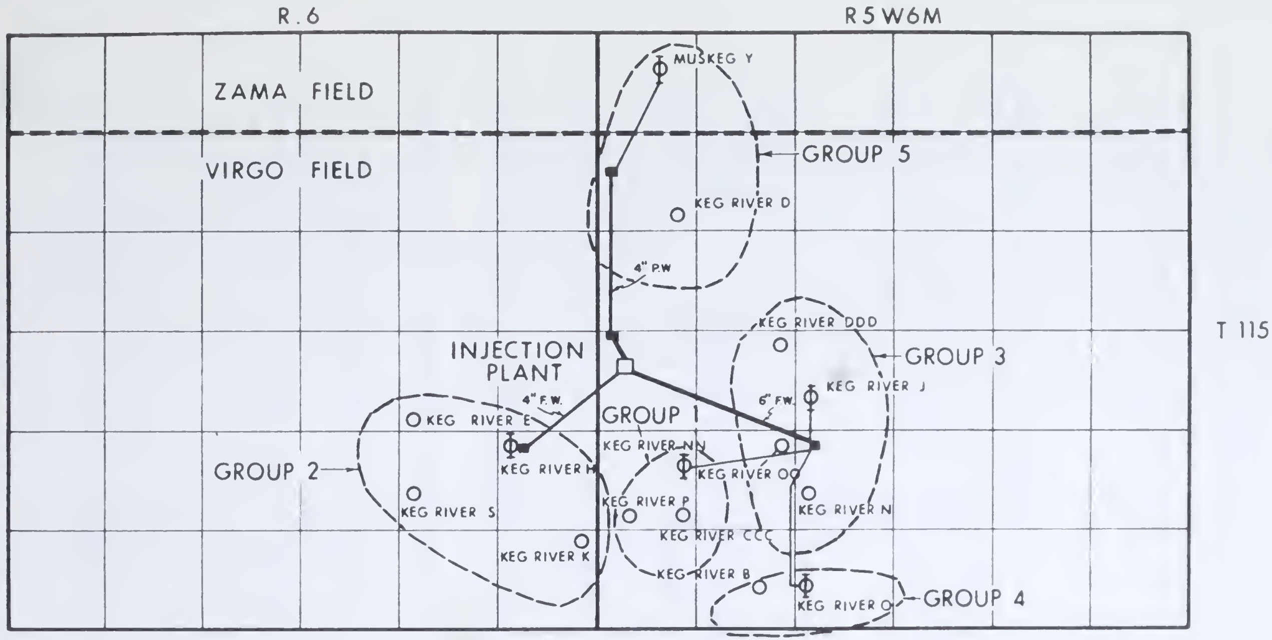

FIGURE 2

WATERFLOOD POOL GROUPS & WATER DISTRIBUTION SYSTEM

REPRODUCED FROM IMPERIAL'S SUBMISSION

■ SATELLITE BATTERY

F.W. FRESH WATER

P.W. PRODUCED WATER

Imperial that where communication with non-scheme pools is significant additional water must be injected to offset these effects. Under such circumstances the Board would wish to review this matter with the owners of the communicating pools. The Board, having regard for the areal extent of the aquifer and the number of pools interconnected through the aquifer, does not agree with Hudson's Bay that interference tests would be conclusive in defining the degree of pressure communication between the pools. The Board believes that the monitoring of the oil-water contact and the pools' pressures will adequately control the effectiveness of the proposed scheme.

RECOGNITION OF ENHANCED RECOVERY

Views of Imperial. Imperial requested that recognition of the enhanced recovery reserve be governed in accordance with section 914 of the Oil and Gas Conservation Regulations. Imperial proposed that where a pool has not exhibited pressure response after 12 months of injection in the group of which the pool is a part, the recovery factor of the pool should be reduced. Further, if a pool fails to show pressure response after a total of 24 months of injection it should be removed from the integrated scheme.

Views of the Board. The Board agrees with Imperial's proposal for initial qualification of the scheme for recognition of enhanced recovery reserves. Since the Board has some doubts concerning the adequacy of interpool communication it believes it appropriate to reduce the recovery factor from a pool at any time that the Board is not satisfied that the enhanced recovery scheme is effective in that pool. The Board believes that Imperial should, for each six-month period for the first two or three years of operation of the scheme, show by production and pressure response that each pool continues to qualify for enhanced recovery recognition.

CONSERVATION ADVANTAGES OF THE PROPOSED INTEGRATED OPERATIONS

Views of Imperial. Imperial stated that "sequential operation under an integrated scheme will result in considerably less sandwich loss due to coning in four of the injection wells than would be the case with simultaneous injection and production". It estimated that in the absence of an integrated scheme the water cone height in the wells used for injection purposes would be greater than the estimated oil accumulation thickness at the start of the water flood and therefore no further oil would be recovered from those pools. Imperial therefore contended that the integrated depletion scheme would result in an increase of about 1.2 million stock tank barrels.

Views of Hudson's Bay. Hudson's Bay stated that "the scheme operation should be based on five separate integrated schemes, since the integration of the five interference groups into one pressure maintenance scheme has not been adequately justified in terms of conservation".

Views of the Board. The Board agrees with Imperial that the oil recovery from any pool where simultaneous injection-production occurs at the same well will be lower than under the proposed integrated scheme. The Board notes that in some actual field cases, where a well is used for both injection and production purposes either on a cyclic operation or a continuous operation, in the Virgo-Zama area the water production from the well increased considerably as a result of coning or mechanical well bore problems. The Board therefore believes that there are greater risks involved in water flooding of the pools where only one well is available for simultaneous injection and production purposes. The Board estimates a conservation advantage of some one million barrels to be attributable to the integrated aspects of the scheme.

With regard to Hudson's Bay's contention that each group of wells in the Imperial proposal should be an independent integrated scheme, the Board believes that there are added conservation advantages in integrating the five groups as proposed by Imperial. The Board accepts Imperial's contention that there will be significant but incalculable gains to be derived from reduced coning and production flexibility resulting from group integration.

THE UNDERTAKING OF THE OPERATORS

Imperial stated that it is prepared to continue the proposed scheme to depletion. The Board accepts this undertaking.

RELIABILITY OF RESERVES ESTIMATES

Views of Imperial. Imperial stated that the crude oil reserves estimates for each pool under integrated operation would be as good as it would be if the pools were produced under a non-integrated scheme. It contended that the proposed reserves are evaluated using volumetric methods, but with more production history and other information gained from monitoring of the scheme, these reserves can further be refined.

Views of the Board. The reserves determined for the proposed pools in the integrated scheme have been primarily on a reservoir model based on individual well data and seismic data. However, pressure production history of some of the pools where the interference effect is not significant was also used to evaluate the oil in place for some pools.

The Board believes that the reserves estimates are as good as for other comparable pools in the Province at the same stage of depletion. The Board expects that the reserves of all the pools in the proposed scheme will be re-evaluated from time to time in accordance with normal practice.

SUITABILITY OF THE PROPOSED ENHANCED RECOVERY SCHEMES

Views of Imperial. Imperial stated that "there are a number of factors that make a miscible flood in the Zama area unattractive, the most important being the relatively low ultimate recovery." Imperial calculated a volumetrically weighted average recovery factor of 49.5 per cent under solvent flooding as compared to a volumetrically weighted average recovery factor of 47 per cent under water flooding. Although some pools show a significantly higher value for solvent flood recovery than water flood recovery, Imperial contended that a solvent flood could not be justified for two or three pools because of the high investment and operating costs.

Views of the Board. The Board notes that the recovery under the various possible depletion mechanisms is dependent on the height of the lower anhydrite and on the volume of oil in the Zama member below the lower anhydrite spill point. The Board has evaluated the recovery factors for the pools in the proposed scheme by primary delpetion, water flood and solvent flood based on its own reservoir configuration described in Decision 70-7. The calculations indicated a volumetric weighted average recovery factor under solvent flood of 68 per cent as compared to 49.5 per cent as determined by Imperial. The Board therefore sees a significant conservation gain attainable by instigating an integrated scheme involving the displacement of the subject pools by a miscible recovery process. The Board assumed that an additional well would be drilled in those pools where the present well is completed in the flank position of the reef. The Board also investigated the availability of solvent and displacing gas supply required for a solvent flood scheme and found that a deficiency existed in these materials if the associated and nearby non-associated gas from properties operated by Imperial were considered available for displacement purposes. While the study was not extensive, these calculations suggested to the Board that a solvent flood would be economically attractive. The Board believes that a scheme involving a combination of solvent flooding and water flooding of the pools in the current proposal and perhaps other pools may be feasible and that Imperial should give this matter its further consideration. In view of the variance in the shape of the geological model and possible inter-pool interference, the Board recognizes that there are some risks in solvent flooding the pools. Accordingly the Board is prepared to approve the scheme for water flooding the proposed pools for an interim period of 18 months to permit Imperial to study further the feasibility of a scheme of solvent flood. During

this period the pressure decline in the pools in the scheme would be arrested and additional information may also become available respecting the pool geometry and the degree and occurrence of interpool interference. Should solvent flooding be found feasible, the 18-month delay in its implementation would not significantly reduce ultimate recovery.

The Board calculated primary depletion and water flood recovery factors of 32 per cent and 22 per cent respectively for the Zama Muskeg Y Pool. Imperial calculated primary depletion and water flood recovery factors of 10 per cent and 30 per cent respectively for this pool. The Board notes that the main difference in the recovery factors is due to the difference in interpretation of the geological model which in turn affects the volume of oil contained in the Zama member. The Board calculations, based on its own model, show that the losses would be greater under water flooding than under primary depletion since by water flooding the oil in the pool above the point of well penetration of the Zama member would be unrecoverable. These losses are greater than the final sandwich losses under primary. The Board is therefore of the opinion that the Zama Muskeg Y Pool should not be water flooded. The well in the pool may be used as an injector but during its producing life the pool should be depleted under a primary depletion mechanism.

The oil in place values and the recoverable oil for the subsisting primary mechanism and for water flooding as established by the Board are summarized in Table 3. The potential gain in recoverable oil attainable through solvent flooding is also shown on Table 3.

DECISION

The Board decides as follows:

1. The Board will approve, under section 38 of The Oil and Gas Conservation Act, 1969, for an interim period ending October 31, 1972, the scheme for enhanced recovery by water flood for those pools except for the Zama Muskeg Y Pool shown in Table 3 of this decision. The Zama Muskeg Y Pool shall be produced under a primary depletion mechanism. The terms and conditions of the approval of the integrated scheme are specified in Approval No. 1468 issued concurrently with this decision.

2. The Board grants, effective on the commencement of the proration period following or coincident with the commencement of water injection substantially in accordance with the scheme approved, the application under section 34, subsection (2) of The Oil and Gas Conservation Act, 1969, for a variation in the manner in which the provincial allowable for crude oil is allocated among the pools of the integrated scheme and for the fixing, in the Board's MD Order, of a single aggregate amount of crude oil that may be produced from the group of pools.

3. Effective March 1, 1971, the ultimate recoverable reserves under the existing depletion mechanism are established as shown in column 4 of Table 3 of this decision report.

4. (1) Effective at a time in accordance with section 914 of the Oil and Gas Conservation Regulations, the ultimate recoverable reserves under water flood except for the Zama Muskeg Y Pool are established as shown in column 6 of Table 3. For the Zama Muskeg Y Pool the ultimate recoverable reserves under primary depletion shown in column 4 of Table 3 shall apply.

(2) The enhanced recoverable reserves established for any pool may be reduced at any time that, in the opinion of the Board, the enhanced recovery mechanism is not effective in the pool. Imperial shall, for each six-month period for the first two years of operation of the scheme, show by production and pressure response that each pool continues to qualify for enhanced recovery recognition.

5. Imperial shall report to the Board by August 31, 1972, on the feasibility of a scheme involving enhanced recovery by solvent flood or a combination of solvent flood and water flood for the pools operated by Imperial in and around the approved scheme.

OIL AND GAS CONSERVATION BOARD

A. F. Manyluk
Deputy Chairman

DATED at Calgary, Alberta
February 12, 1971

OIL AND GAS ,ERVATION BOARD

TABLE 1 TO DECISION 71-2

COMPARATIVE RESERVOIR PARAMETERS AND OIL IN PLACE
FROM SUBMISSION AND AS SET BY THE BOARD

POOL	OIL ZONE RES. VOL. (ACRE FT.)		AREA (ACRE)		THICKNESS, H (FEET)		POROSITY, Ø (FRACTION)		WATER SAT., Sw (FRACTION)		SHRINKAGE 1/Boi		OIL IN PLACE, N (MSTB)	
	IMPERIAL	BOARD	IMPERIAL	BOARD	IMPERIAL	BOARD	IMPERIAL	BOARD	IMPERIAL	BOARD	IMPERIAL	BOARD	IMPERIAL	BOARD
VIRGO KR[1] B	4,635	4,420	62.7[3]	32[4]	128	128	0.094	0.094	0.140	0.11	0.867	0.87	2,520	2,500
VIRGO KR D	8,852	6,370	122.5	38	223	223	0.088	0.090	0.145	0.10	0.845	0.85	4,366	3,400
VIRGO KR E	9,476	7,250	123.0	46	224	224	0.094	0.094	0.141	0.10	0.839	0.82	4,980	3,900
VIRGO KR H	8,791	7,420	117.8	50	226	224	0.092	0.093	0.140	0.10	0.827	0.83	4,462	4,000
VIRGO KR J	3,766	3,240	49.6	21	122	122	0.053	0.053	0.170	0.14	0.870	0.87	1,117	1,000
VIRGO KR K	2,676	1,590	71.6	14	220	219	0.067	0.065	0.210	0.12	0.845	0.85	929	600
VIRGO KR N	2,975	2,300	48.6	17	151	151	0.073	0.073	0.170	0.12	0.850	0.87	1,191	1,000
VIRGO KR O	2,153	2,550	37.8	11	150	172	0.066	0.066	0.187	0.12	0.870	0.87	780	1,000
VIRGO KR P	6,485	4,630	88.8	33	244	244	0.081	0.081	0.149	0.10	0.820	0.84	2,844	2,200
VIRGO KR S	3,698	3,860	53.3	30	214	243	0.072	0.077	0.140	0.10	0.830	0.82	1,457	1,700
VIRGO KR NN	1,979	1,530	39.1	9	189	188	0.110	0.110	0.181	0.09	0.853	0.84	1,180	1,000
VIRGO KR OO	3,015	2,430	40.2	19	122	115	0.061	0.070	0.160	0.13	0.353	0.86	1,022	1,000
VIRGO KR CCC	8,046	3,490	100.2	22	212	224	0.065	0.065	0.150	0.12	0.838	0.84	2,432	1,300
VIRGO KR DDD	2,698	2,490	45.1	16	140	148	0.085	0.082	0.160	0.11	0.783	0.85	1,170	1,200
ZAMA MU[2] Y	8,311	3,590	103.0	22	243	184	0.078	0.075	0.150	0.11	0.862	0.86	3,685	1,600
											TOTAL		34,135	27,400

(1) VIRGO KEG RIVER POOL

(2) ZAMA MUSKEG POOL

(3) AREA OF THE KEG RIVER AT THE OIL-WATER INTERFACE PLUS THE AREA OF THE ZAMA AT THE OIL-WATER INTERFACE

(4) AREA OF THE KEG RIVER AT THE OIL-WATER INTERFACE

OIL AND GAS CONSERVATION BOARD

TABLE 2 TO DECISION 71-2

COMPARISON OF RECOVERY FACTORS FOR DIFFERENT RECOVERY MECHANISMS

POOL	PRIMARY PER CENT		WATER FLOOD PER CENT		SOLVENT FLOOD PER CENT	
	IMPERIAL	BOARD	IMPERIAL	BOARD	IMPERIAL	BOARD
Virgo Keg River B	30	37	51	49	68	67
Virgo Keg River D	25	40	53	52	53	70
Virgo Keg River E	26	38	54	52	53	70
Virgo Keg River H	20	38	53	52	51	69
Virgo Keg River J	24	38	49	48	67	68
Virgo Keg River K	10	38	39	52	20	64
Virgo Keg River N	20	38	45	50	45	65
Virgo Keg River O	10	38	43	44	30	67
Virgo Keg River P	22	40	45	53	48	68
Virgo Keg River S	12	39	44	47	25	67
Virgo Keg River NN	13	40	32	52	30	68
Virgo Keg River OO	25	37	50	48	64	65
Virgo Keg River CCC	19	40	43	50	49	69
Virgo Keg River DDD	22	39	46	47	47	67
Zama Muskeg Y	10	32	30	22	-	69
Volumetric Weighted Avg.	20	38	47	49	49.5	68

OIL AND GAS CONSERVATION BOARD

TABLE 3 TO DECISION 71-2

SUMMARY OF RECOVERABLE RESERVES AS DETERMINED BY THE BOARD

POOL	OIL IN PLACE (MSTB)	SUBSISTING PRIMARY DEPLETION MECHANISM		WATER FLOOD		SOLVENT FLOOD	
		RECOVERY FACTOR %	ULTIMATE RESERVES (MSTB)	RECOVERY FACTOR %	ULTIMATE RESERVES (MSTB)	RECOVERY FACTOR %	ULTIMATE RESERVES (MSTB)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Virgo Keg River B	2,500	37	925	49	1,230	67	1,680
Virgo Keg River D	3,400	40	1,360	52	1,770	70	2,380
Virgo Keg River E	3,900	38	1,480	52	2,030	70	2,730
Virgo Keg River H	4,000	38	1,520	52	2,080	69	2,760
Virgo Keg River J	1,000	38	380	48	480	68	680
Virgo Keg River K	600	38	228	52	312	64	384
Virgo Keg River N	1,000	38	380	50	500	65	650
Virgo Keg River O	1,000	38	380	44	440	67	670
Virgo Keg River P	2,200	40	880	53	1,170	68	1,500
Virgo Keg River S	1,700	39	663	47	799	67	1,140
Virgo Keg River NN	1,000	40	400	52	520	68	680
Virgo Keg River OO	1,000	37	370	48	480	65	650
Virgo Keg River CCC	1,300	40	520	50	650	69	897
Virgo Keg River DDD	1,200	39	468	47	564	67	804
Zama Muskeg Y	1,600	32	512	22	352	69	1,100
TOTAL	27,400		10,500		13,400		18,700

OIL AND GAS CONSERVATION BOARD

Decision 71-
Application No. 5383

GAS PROCESSING - CROSSFIELD FIELD
PETROGAS PROCESSING LTD.

INTRODUCTION

The Crossfield Plant of Petrogas Processing Ltd. (hereinafter called "Petrogas") is currently operated under Board Approval No. 843, issued April 1, 1966, and Provincial Board of Health Interim Air Pollution Approval No. 1092-P-265, dated November 13, 1969. The interim air pollution approval amended Final Air Pollution Approval No. 225-P-265, dated March 15, 1966.

THE APPLICATION AND HEARING

Petrogas Processing Ltd. applied under section 38, clause (b) of The Oil and Gas Conservation Act, 1969, for an interim amendment of Board Approval No. 843 and Provincial Board of Health Interim Air Pollution Approval No. 1092-P-265. The amendment of Board Approval No. 843 applied for would require a sulphur recovery of 95 per cent rather than the 97 per cent now specified; the amendment of Provincial Board of Health Interim Air Pollution Approval No. 1092-P-265 applied for would permit emission to the atmosphere of a maximum of 171 long tons per day of sulphur dioxide through the two existing 400-foot stacks until June 30, 1972, and authorize operation of the plant up to design load conditions, notwithstanding the sulphur dioxide emission rate, if on the basis of a standard of 0.2 parts per million averaged over a one-half hour period, the maximum concentration of sulphur dioxide measured at any of three ground level monitoring stations does not exceed 0.2 parts per million averaged over a fifteen-minute period.

A submission in opposition to the application was filed by the Department of Health of the Government of the Province of Alberta. The application was heard on December 14, 1970 by Board members G. W. Govier, P. Eng. and A. F. Manyluk, P. Eng..

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Petrogas Processing Ltd.	H. B. Shelton	Petrogas
	R. S. Blackett, P. Eng.	
	W. W. Chalmers	
	J. Lukas, P. Eng. (of Western Research and Development Ltd.)	
	R. Rankine (of Western Research and Development Ltd.)	

	Represented by	Abbreviation Used in Report
Department of Health	S. L. Dobko, P. Eng. P. M. Ullman, P. Eng.	Department
Board Staff	G. J. DeSorcy, P. Eng. L. A. Mazurek, P. Eng. R. B. Dunbar, P. Eng.	

PROVISIONS OF PRESENT APPROVALS

Approvals No. 843 and No. 225-P-265 require that the plant be operated at a minimum sulphur recovery of 97 per cent and a maximum sulphur dioxide emission rate through the two existing 400 foot stacks of 122 long tons per day at a minimum emission temperature of 1000° degrees Fahrenheit (°F). Interim Air Pollution Approval No. 1092-P-265 permitted higher sulphur dioxide emissions for a period of 14 months and was issued to allow Petrogas to operate the plant at full capacity while testing the facilities in an effort to improve the efficiency of sulphur recovery. The interim approval permitted the emission of a maximum of 213 long tons of sulphur dioxide per day at a minimum stack exit temperature of 1100°F from November 1969 to March 31, 1970, and a maximum of 171 long tons of sulphur dioxide per day, at a minimum stack exit temperature of 1100°F, from April 1, 1970 to October 31, 1970, and thereafter the maximum sulphur dioxide emission of 122 long tons per day specified by Approval No. 225-P-265. The interim approval was amended by the Board by letters dated October 27, 1970, December 23, 1970 and January 19, 1971, to extend until February 28, 1971, the period over which a maximum of 171 long tons per day of sulphur dioxide could be emitted to the atmosphere. These amendments were granted with the concurrence of the Provincial Board of Health.

DEFINITION OF ISSUES INVOLVED

The Board considers the following to be the main issues:

(a) the ground level sulphur dioxide concentration standard,

(b) the sulphur recovery efficiency,

(c) the suitability of the proposed ground level monitoring system,

(d) the maximum sulphur dioxide emission limit.

GROUND LEVEL SULPHUR DIOXIDE CONCENTRATION STANDARD

(1) Views of the Applicant

Petrogas based its application on a standard of a maximum one-half hour average concentration of sulphur dioxide at ground level

of 0.2 parts per million. This is the standard normally applied in populated areas or where agricultural crops are grown. The applicant contended that this concentration is referred to as the standard in a letter from the Department to Petrogas, dated November 26, 1968, marked as Exhibit 26 at the hearing.

(2) Views of the Department

The Department stated that the intended Provincial Board of Health standard for the area is 0.15 parts per million maximum one-half hour average sulphur dioxide concentration at ground level. This concentration is lower than the normal standard of 0.20 parts per million due to the proximity of the plant to the City of Calgary and the concern that the health of many citizens of Calgary and surrounding areas could be affected if higher concentrations were permitted.

The Department stated that the letter which made reference to a standard of 0.20 parts per million was in error. It referred to a number of earlier letters and a more recent letter from the Department to Petrogas, dated April 11, 1969, and marked as Exhibit 17 at the hearing, which refers to a maximum concentration of 0.15 parts per million.

(3) Views of the Board

The Board believes that a maximum one-half hour average concentration of sulphur dioxide of 0.15 parts per million at ground level, as set by the Provincial Board of Health, is the proper standard for the scheme area.

SULPHUR RECOVERY EFFICIENCY

(1) Views of the Applicant

Petrogas stated that recent plant efficiency testing has indicated that the practical sulphur recovery for the existing facilities is approximately 95 per cent and not 97 per cent as specified by Approval No. 843. The applicant stated that it would appear that the plant never has been capable of 97 per cent sulphur recovery. It was and is capable of a 97 per cent efficiency as measured using standard designer/contractor tests, but these tests measure only coalescer sulphur dioxide and hydrogen sulphide effluent and do not account for efficiency losses due to the presence of other sulphur compounds, entrained sulphur liquid and sulphur vapour in the plant tail gas.

Petrogas contended that progress has been made in the last 12 to 18 months in improving the sulphur recovery efficiency. Recovery efficiency improvements have restuled from: frequent catalyst changes, modifications to reduce the carry-over of liquid hydrocarbons and amine from the treating plant, conducting plant performance tests and making resultant operational changes, installing temperature and ratio control to automatically control the air to acid gas ratio on the auxillary

burners, installing mist eliminators in the first and second condensers, and installing two gas chromatographs to continuously monitor the plant tail gas streams for sulphur dioxide - hydrogen sulphide ratio.

The applicant stated that it requires the interim reduction in recovery factor so that it might study further the following operating problems at full plant capacity:

(a) formation and conversion of organic sulphur compounds,

(b) entrainment of free sulphur in the tail gases to the incincerator,

(c) entrainment of free sulphur in the gases leaving the interstage sulphur condensers,

(d) catalyst deactivation, and

(e) process control problems caused by variations in ambient temperature and plant loading.

Petrogas said that the study would take approximately 18 months.

Petrogas stated that the proposed study and resultant modifications might result in an improved sulphur recovery efficiency somewhere between 95 and 98 per cent. For this reason it suggested the study should be allowed and completed prior to any determination of whether a tail gas recovery process is required. The results of the study would also be required to design any additional major facilities that may be needed.

In addition to the proposed study and plant modifications, Petrogas stated it also supports the Alberta Sulphur Research Limited three year research project of the "front-end combustion process" in Claus sulphur plants and has also adopted a "posture of active surveillance" of the various "tail-end" processes for clean-up of sulphur plant tail gases.

(2) Views of the Department

The Department indicated that it is primarily concerned with the total emission of sulphur dioxide to the atmosphere and the resultant ground level sulphur dioxide concentrations and is only indirectly concerned with the sulphur recovery efficiency. Having regard to the total emission, however, the Department stated that it would not find operation of the plant at full throughput to be acceptable unless a 97 per cent sulphur recovery efficiency was maintained. It expressed the opinion that this cannot be achieved with the existing facilities and that some type of tail gas recovery process is required. The Department recommended that the installation of tail-gas recovery facilities be planned immediately.

(3) Views of the Board

The 97 per cent sulphur recovery currently required by Approval No. 843 is that which the applicant stated could be maintained in its earlier application to the Board for an approval of the existing facilities. Having regard to the nature of the gas, the number of catalytic stages and the type of process, the Board now agrees that 95 per cent is close to the presently attainable maximum. The Board is not optimistic that 97 per cent is attainable on a continuous basis from the present facilities, even if modified, and moreover anticipates that a recovery of more than 97 per cent will be required in the future. The Board believes that some improvement over the 95 per cent can be made with the existing facilities but, bearing in mind the interim approval granted on November 1, 1969, believes that the improvement should be attained in less than 18 months. The Board expects that a tail gas recovery process will ultimately be required to meet a future higher recovery standard and believes that a study of such processes should commence immediately.

The Board believes it proper that the present approval should be amended to require a minimum recovery of 95 per cent to December 31, 1971, and a minimum recovery of 96 per cent for the period from January 1, 1972 to December 31, 1973. The Board further believes that on and after January 1, 1974 the minimum recovery should be in the range of 97 to 99 per cent, such recovery to be determined by the Board following the receipt of representations from Petrogas before June 30, 1972.

PROPOSED GROUND LEVEL MONITORING SYSTEM

(1) Views of the Applicant

Petrogas expressed the opinion that the proposed monitoring system is adequate to give complete coverage in the area surrounding the plant. The Nose Hill location was chosen because of its elevation and proximity to the developed area of the City of Calgary. The other two stations are located in the direction of the prevailing winds where the highest sulphur dioxide concentrations most probably would occur. Stations were not proposed to the north and west of the plant because, in the opinion of the applicant, concentrations exceeding 0.2 parts per million averaged over one-half hour would not occur in these directions.

The applicant claimed that ground level monitoring as a means of pollution control would be superior to the present control method based on an emission limit determined by calculation of ground level concentrations. Petrogas also stated that measured sulphur dioxide concentrations and sulphation levels in the vicinity of the plant indicate that the emission calculations give excessively conservative results. It suggested that this is supported by observations for the twelve month period ending June 30, 1970 when sulphur dioxide concentrations exceeding 0.2 parts per million were recorded at the two existing monitoring stations less than 0.1 per cent of the time.

(2) Views of the Department

The Department expressed opposition to the ground level monitoring method as a means of pollution control because of the limited coverage possible and the unpredictability of meteorological conditions. Further it stated that experimentation of the nature proposed in the application should not be permitted near a large urban centre.

The Department stated that it believes the calculated emission limit approach to plant pollution control is superior to one based upon ground level monitoring. It offered evidence that the Department trailer recorded significant instantaneous sulphur dioxide readings 37 per cent of the time there was a wind from the plant toward the trailer during December 1969 and 11 per cent of the time there was a wind from the plant toward the trailer during July 1970. The peak instantaneous reading recorded during the July 1970 survey was 7 parts per million. The Department therefore concluded that the calculations of ground level concentrations are in fact not conservative as suggested by the applicant. It stated that exposure cylinders which it maintained in the area also indicated increasing sulphation levels since 1965, which is contrary to the claims made by Petrogas.

While opposing the application respecting ground level monitoring stations as a means of pollution control, the Department stated that if the application were approved additional monitoring stations, full telemetering and duplicate sulphur dioxide analyzers to ensure reliability and continuity of operation should be required.

(3) Views of the Board

Board staff calculations of ground level concentrations suggest that operation of the Petrogas plant at the currently approved maximum sour gas inlet capacity at a recovery efficiency of 95 per cent (equivalent to a sulphur dioxide emission rate of approximately 200 long tons per day) could result in ground level sulphur dioxide concentrations exceeding the 0.15 parts per million standard over some 75 to 100 square miles and in any direction from the plant depending on the wind condition. In the opinion of the Board the system proposed by Petrogas is not satisfactory because the three monitoring stations cannot provide adequate coverage over the large area which could be affected.

On the other hand, the Board believes that subject to adequate design and operation of the system and an overall limitation on the total emission, the ground level monitoring approach is an acceptable method for pollution control. Accordingly, the Board is prepared to approve the use of ground level monitoring by Petrogas subject to certain conditions and if it alters appropriately the design of its system. The ideal system would give total coverage with continuous ground level monitors which are accurate and reliable, duplicated by stand-by equipment, and from which the results are continuously transmitted to the plant. Since complete coverage is not practically possible

the Board believes that an optimum number of stations could be located to provide coverage of the critical areas and that maximum emission rate control could be applied to minimize the possibility of undetected higher concentrations occurring between stations. The Board also believes that with less than total coverage it would be necessary for the plant to initiate corrective action at some concentration less than the standard since it is probable that a concentration exceeding the standard could exist within the area of interest and not be detected by one of the stations. The time lag which occurs between the instant of emission and the time the pollutant reaches a monitoring station also makes it desirable to initiate corrective action at some detecting concentration less than the standard to lessen the possibility of the standard being exceeded before the corrective action is effective. The Board notes that the applicant also recognized this need in that its system, although based on a one-half hour standard, involved initiating corrective action when concentrations exceeding the standard occured over a fifteen-minute period.

On the basis of calculated ground level sulphur dioxide concentrations, wind velocity and frequency data for the area, and having regard for the population distribution and topography, the Board is of the opinion that a minimum of seven monitoring stations is required to give adequate coverage. This assumes that under no circumstances would the sulphur dioxide emission rate exceed 200 long tons per day at a minimum emission temperature of 1100°F. In addition the Board believes that facilities should be provided to transmit measured sulphur dioxide concentrations continuously from each monitor to the plant and that satisfactory corrective action would be initiated as soon as a sulphur dioxide concentration exceeding 0.15 parts per million, averaged over a fifteen-minute period, is detected at one or more stations. Additional detail regarding the requirements for an acceptable monitoring system is given later in this report.

With respect to the calculation of total emission rates from stack height and prescribed ground level concentrations, the Board agrees that some safety factor may exist under certain atmospheric conditions, but believes that this situation is desirable. Information submitted by the Department indicates that under more adverse dispersion conditions the calculations may in fact underestimate the ground level concentrations. The Board believes that the dispersion calculation methods which it normally uses (Sutton-Lowry and Pasquill) incorporate a satisfactory balance between overestimating and underestimating pollutant concentrations.

SULPHUR DIOXIDE EMISSION LIMIT

(1) Views of the Applicant

While Petrogas applied to have the sulphur dioxide emission limit waived in light of the proposed ground level monitoring it stated that operation of the plant at a maximum sulphur dioxide emission limit

of 171 long tons per day at 95 per cent sulphur recovery and a stack exit temperature of 1100°F, would not result in ground level sulphur dioxide concentrations exceeding the standard (interpreted by the applicant to be 0.2 parts per million for one-half hour) to any meaningful degree. The applicant stated that the calculated concentrations would be higher than observed concentrations more than 95 per cent of the time. For this reason the applicant expressed the opinion that operation of the facilities up to this emission limit, without ground level monitoring control, would not have detrimental effects on the surrounding area.

(2) Views of the Department

The Department recommended that the total sulphur dioxide emission rate be maintained at a value not to exceed 122 long tons per day. This figure is based on its calculation for a maximum ground level sulphur dioxide concentration of 0.15 parts per million for one-half hour. The Department also recommended that the composite flow rate from both stacks be maintained at a minimum of 3,650 cubic feet per second regardless of plant input, and that continuous sulphur dioxide monitoring equipment be installed in the stacks as soon as possible. The Oil and Gas Conservation Regulations require the installation of such equipment by September 1, 1971.

(3) Views of the Board

In the opinion of the Board it is necessary to consider two separate sulphur dioxide emission limits: one for operation without ground level monitoring control, and one for operation with continuous and satisfactory ground level monitoring control. The emission limit applicable without ground level monitoring control would be calculated from prescribed maximum ground level sulphur dioxide concentrations. The emission limit to apply with ground level monitoring would be less restrictive due to the additional control obtained by the use of continuous ground level monitoring.

The Board considers the sulphur dioxide emission rate of 171 long tons per day applied for by the applicant, without the additional control which would be provided by suitably located continuously operating ground level monitors, to be unacceptable. This conclusion is based on calculations which indicate that sulphur dioxide ground level concentrations exceeding 0.15 parts per million could result in essentially any direction from the plant should certain wind conditions exist. The Board believes that in the absence of a ground level monitoring system an emission rate of 122 long tons per day should not be exceeded but agrees with the Department that such a rate would be acceptable only if the emission temperature and stack gas flow rate were maintained as required by the Department approval. Information available to the Board indicates that the total stack gas flow would normally be less than the required 3,650 cubic feet per second if the plant were operating at 95 per cent sulphur recovery. Accordingly, some modification to the method of operation (such as adding supplemental fuel and air to the incinerators, increasing the stack exit temperature, or utilizing

only one stack instead of two) would be required in order that emission of 122 long tons per day would not result in possible excess ground level concentrations. The Board also recognizes the possibility that other operating changes could result in an acceptable emission rate without ground level monitoring control which would be higher than 122 long tons per day.

The Board believes that with the system of ground level monitoring control which it is prepared to approve a sulphur dioxide emission limit of 200 long tons per day would be acceptable. This limit is that which corresponds to operating the plant at maximum sour gas inlet capacity and at a sulphur recovery of 95 per cent.

DECISION

1. The Board accepts the maximum one-half hour average concentration of sulphur dioxide of 0.15 parts per million at ground level, as set by the Provincial Board of Health, as the standard for the area.

2. The Board will grant that part of the application to amend Approval No. 843 to require a reduced sulphur recovery efficiency for an interim period, to terminate December 31, 1973, subject to the following conditions:

(1) The sulphur recovery shall be a minimum of 95 per cent of the sulphur contained in the raw gas delivered to the plant during each three month petiod beginning January 1, April 1, July 1, or October 1 from January 1, 1971 to December 31, 1971.

(2) The sulphur recovery shall be a minimum of 96 per cent of the sulphur contained in the raw gas delivered to the plant during each three month period beginning January 1, April 1, July 1 or October 1 from January 1, 1972 to December 31, 1973.

(3) The sulphur recovery required after December 31, 1973 shall be in the range of 97 to 99 per cent and shall be determined by the Board following a meeting with Petrogas before June 30, 1972.

3. The Board grants that part of the application to use ground level monitoring for pollution control subject to the following conditions:

(1) A minimum of seven monitoring stations, shall be in operation at all times.

(2) The stations shall be located satisfactory to the Board. For the initial operation the Board approves the locations of the two existing monitors and the Nose Hill station proposed in the application. The other four monitors shall be located in approximately the following locations:

(a) Section 27 of Township 25, Range 29, West of the 4th Meridian,

(b) Section 18 of Township 26, Range 28, West of the 4th Meridian,

(c) Section 16 of Township 26, Range 29, West of the 4th Meridian, and

(d) Section 24 of Township 26, Range 29, West of the 4th Meridian.

(3) Facilities to transmit measured sulphur dioxide concentrations continuously from each station to the plant shall be in operation at all times.

(4) Satisfactory corrective action shall be initiated as soon as a sulphur dioxide concentration exceeding 0.15 parts per million, averaged over a fifteen-minute period, is detected at one or more stations.

(5) The corrective action shall be maintained for a period of time sufficient to ensure that the measured concentrations have stabilized, for a minimum of one hour, well below 0.15 parts per million, averaged over a fifteen-minute period.

(6) The sulphur dioxide emission rate shall not exceed 200 long tons per day under any circumstances.

(7) The stack gas exit temperature shall be a minimum of 1100°F.

(8) After the installation of the required monitoring facilities the sulphur dioxide emission rate shall be a maximum of 122 long tons per day when any of the ground level monitoring equipment is not in service unless approval to operate at some other emission rate is obtained from the Board.

4. The Board recognizes that some time will be required to install the four additional monitors and so will permit Petrogas to use the existing three station monitoring system for pollution control for an interim period, which would terminate on October 31, 1971, or, if achieved prior to this date, at the start-up of the approved seven station monitoring system. During this period the sulphur dioxide emission limit will be 150 long tons per day unless some of the existing monitoring equipment is not in service, at which time the sulphur dioxide emission limit will be 122 long tons per day. Telemetering shall be installed at all stations at the earliest possible date. Until that time the stations shall be attended in a manner satisfactory to the Board.

5. The Board will require that the sulphur dioxide emission rate be a maximum of 122 long tons per day and that the stack gas flow rate be a minimum of 3,650 cubic feet per second at the 122 long ton emission rate after October 31, 1971 if the applicant decides against using ground level monitoring control or until the start-up of an acceptable ground level monitoring system. However, the Board would be prepared to approve other conditions of emission which would meet the calculated ground level standard.

6. The Board may alter the terms of the approval, if in its opinion, circumstances so warrant.

OIL AND GAS CONSERVATION BOARD

G. W. Govier
Chairman

DATED at Calgary, Alberta
February 18, 1971

OIL AND GAS CONSERVATION BOARD

Decision 71-4
Proceeding No. 5124

Olds Wabamun A Pool Enhanced Recovery and Good Production Practice

THE APPLICATION AND HEARING

The hearing was called to consider the following matters respecting the Olds Wabamun A Pool:

(1) establishment of a water fence between the gas cap and the oil zone;

(2) enhanced recovery of crude oil by water injection or other methods;

(3) reconsideration of good production practice for oil wells as provided for in Board Decision 68-12.

The proceeding was initiated by the Board following a submission by its staff. Additional submissions were made by Shell Canada Limited and Amerada Hess Corporation. BP Oil and Gas Ltd. filed a submission in response to and supporting the position of Shell Canada Limited.

The hearing took place before the Board, with A. F. Manyluk, P. Eng., V. Millard, and D. R. Craig, P. Eng. sitting. The hearing opened on September 9, 1970, and was adjourned to and completed on October 28, 1970.

Following the hearing, the Board staff made additional studies at the request of the Board. On January 4 and 22, 1971, the Board met representatives of the parties registered at the hearing to review the additional studies and receive comments thereon.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Shell Canada Limited	H. Lyon R. G. Gorrill, P. Eng. J. W. Serra, P. Eng.	Shell
Amerada Hess Corporation	E. N. Patton R. P. Cummer, P. Eng. F. T. Nadir, P. Eng. J. Patterson, P. Eng.	Amerada
BP Oil and Gas Ltd.	R. G. Kessler, P. Eng.	BP
Board Staff	N. A. Strom, P. Eng. H. R. Keushnig, P. Eng. J. R. Nichol, E.I.T.	Board staff

BACKGROUND

Upon Decision 68-11, issued in August 1968, the Board approved a scheme for continued concurrent production of the oil accumulation and gas cap in the Olds Wabamun A Pool but restricted the combined gas production from the gas cap and oil accumulation to not more than the existing rate of 41 million cubic feet per day. The decision had regard for recoveries and present value profit from the oil accumulation and gas cap under primary depletion at various permitted rates of production. It also took into consideration the fact that the gas cap had been developed and a processing plant built prior to the discovery of the oil accumulation. Decision 68-12, issued simultaneously with Decision 68-11, granted good production practice (GPP) for the oil accumulation to allow oil production at a rate much higher than the normal prorated rate in order to reduce losses of crude oil that would otherwise occur due to concurrent production of the gas cap. The Board stated in Decision 68-12 that the matter of GPP would be subject to reconsideration upon completion of detailed enhanced recovery studies.

Further conditions were contained in separate letters from the Board to Shell and Amerada dated August 30, 1968. Amerada was required to study the desirability of injecting water updip from the oil accumulation to create a water buffer zone (water fence) between the gas cap and the oil accumulation and the desirability of a partial gas cycling scheme with injection of gas in the vicinity of the oil accumulation. Shell was required to review and update pool continuity studies, and, to determine the feasibility of all appropriate forms of oil recovery enhancement including, in particular, the injection of water updip along the gas-oil interface to create a water fence between the gas cap and the oil accumulation. The studies were to be submitted at the end of 1969.

The above decisions relied heavily on reservoir simulation studies made by D. R. McCord and Associates, Inc. in August 1967. Since the time of the above decisions, three reviews updating the original McCord study have been made and submitted to the Board by Shell. The reviews confirm the existence of reservoir continuity and the pool configuration roughly as depicted in the original study.

Shell submitted its appraisal of oil recovery enhancement by water injection and by gas cycling in a report dated December 31, 1969. Shell estimated that by using a water injection scheme there would be an incremental gain in producible crude oil reserves of approximately 4 million stock tank barrels (STB). It concluded, however, that oil recovery enhancement by water injection was not economically justified relative to continued primary depletion at GPP rates and having regard for the risks involved. Also it concluded that a partial gas cycling scheme with gas injection in the vicinity of the gas-oil contact might provide an incremental gain in crude oil recovery of 3 million STB, but that the economic feasibility of such a scheme would require further investigation.

Subsequent to receipt of the Shell studies, the Board staff performed preliminary studies and reached conclusions confirming Shell's findings that

additional oil recovery could be realized by water injection. On the basis of the potential for significant oil recovery improvement indicated in both the Shell and Board staff studies, the Board considered it appropriate to call the hearing to consider the three main questions cited in the notice.

SUBMISSIONS

Board Staff

The Board staff performed studies respecting the establishment of a water fence between the oil accumulation and the gas cap by the injection of water in several appropriately situated wells, and enhanced recovery of crude oil by water flooding. The Board staff primary submission was tendered on June 18, 1970, and amended to incorporate two dimensional reservoir studies on October 9, 1970. Based on its studies, the Board staff concluded that a water fence should be established along the southern part of the gas-oil contact to minimize fluid migration toward the gas cap and that this measure would lead to an incremental gain in oil recovery of 2.1 million STB over the status quo. The Board staff maintained that the number of water injection wells could be kept to a minimum by limiting the water fence to the southern part of the gas-oil contact.

Upon the direction of the Board following the hearing, the Board staff performed additional studies of downdip water injection plus investigations of the economics of each of the methods of depletion under consideration. Results of these studies were made available to all participants at a meeting on January 4, and by letter dated January 8, 1971. These studies indicated that there would be a gain in oil recovery of up to 4.3 million STB with a gain in present value profit before tax (hereafter called present value profit) of about $1.7 million when compared with primary depletion at the present GPP production rates.

Regarding the matter of primary GPP rates, the Board staff briefly investigated the relationship of rate of oil production to ultimate oil recovery under primary depletion. It concluded that there would not be significant oil recovery benefits at rates beyond 2000 barrels per day. The Board staff also concluded that restoring proration in the oil zone for the immediate five-year period followed by GPP would yield almost the same oil recovery as would be obtained under continuation of existing GPP rates. When this conclusion was disputed by Shell at the hearing, the Board staff agreed that the conclusion might not be well founded.

Shell

Shell, on behalf of Olds Unit No. 2 (oil accumulation unit), submitted the following conclusions in its primary submission dated August 21, 1970:

(1) Oil wells in the Olds Wabamun A Pool should continue to be produced on a good production practice basis in order to maximize oil recovery.

(2) Enhancement of oil recovery by water injection in the Olds Wabamun A Pool could yield a maximum of 1.7 million barrels of additional crude oil but is not economically justified (relative to present GPP status).

(3) Enhancement of oil recovery by gas injection in the Olds Wabamun A Pool could yield a maximum of 1.3 million barrels additional oil recovery but is not economically justified (relative to present GPP status).

Shell provided production schedules, product prices and cost data to support its conclusions. The crude oil recoveries were much lower than those estimated in studies submitted on December 31, 1969.

In its intervention dated October 20, 1970, Shell disagreed with the Board staff that oil recovery would not be significantly affected by restoring proration for a five-year interval. Shell submitted that the major portion of benefits to oil recovery from oil column withdrawals at the higher rates permitted under GPP are realized early in the remaining pool life.

Pursuant to the information respecting water flooding provided in the Board staff tabulations made available on January 4 and January 8, 1971, Shell provided a table of comparison of oil recoveries and incremental economics, all referred to the present GPP status, which showed that water flooding would not be economically justified even if the Board staff recovery estimates were adopted.

BP

BP supported Shell's general position. In addition, it expressed concern about the possibility of water intrusion into the gas well in Legal Subdivision 10 of Section 34, Township 32, Range 2 West of the 5th Meridian if a scheme of injection of water at the gas-oil interface were implemented.

Amerada

Amerada, on behalf of Olds Unit No. 1 (gas cap unit), submitted that injection of water along the gas-oil interface would have no adverse effect on the gas cap. Its conclusion was based on two dimensional reservoir studies simulating a water fence in the southern part of the gas-oil contact.

DEFINITION OF ISSUES

The Board sees the main issue to be technical and economic feasibility of the various recovery schemes.

Prior to considering the main issue, the Board considers it necessary to resolve certain preliminary issues having a bearing on technical and economic feasibility. Defining the basis (reference case) for evaluating the various recovery schemes, and, resolving the status of GPP and the possible production of the gas cap located in and near Section 34, Township 33, Range 2 West of the 5th Meridian (henceforth called the north-east gas cap) are the preliminary issues considered below.

REFERENCE CASE

Views of the Board Staff

The Board staff made no explicit recommendation as to the reference case to be applied for the purpose of comparison. It included in its evaluations, incremental recovery compared to both primary depletion under the proration plan (primary prorated) and primary depletion under GPP (primary GPP) as possible reference cases.

Views of Shell

Shell clearly indicated both in its submission and testimony that it considered the recoveries and economics of primary GPP (i.e. the status quo) should be the base against which alternative schemes should be judged.

Views of the Board

The Board, in Decision 68-12, granted an increased rate of oil accumulation production by assigning GPP under primary depletion in order to avoid undue losses of oil recovery for the interim period while studies of enhanced recovery were being performed. At the 1968 hearing, the Board received assurance from Shell that granting of GPP would not reduce the prospects for enhanced oil recovery at a later date. The issue is whether primary GPP, having been approved on an interim basis in 1968, should represent the reference against which alternative recovery schemes should now be assessed or whether the original primary prorated production method should be the reference. The Board believes that, in as much as GPP was granted on an interim basis only and subject to enhanced recovery studies, the reference case must be the original depletion method (i.e. primary prorated). Application of this conclusion would be subject to the qualification that any enhanced recovery scheme being considered must provide a significant improvement in recoveries from the pool over that obtained by primary GPP.

STATUS OF GPP

Views of the Board Staff

The Board staff made no direct representations concerning the status of GPP. However, the Board staff predictions made available in January 1971 utilized the current GPP crude oil production rates in the enhanced recovery predictions.

Views of Shell

Shell, in a letter dated November 10, 1970, containing certain additional information requested at the hearing, entered the following statement:

"During the hearing on October 28, 1970, the Board examiners and Board staff raised questions regarding the base case for comparing the economics of a water flood. We wish to take this opportunity to clarify our position. As indicated in the May 1968 hearing and as recorded in Decision 68-12 page 3, Shell's view regarding the merits of enhanced recovery was, and continues to be: 'means of increasing oil recovery must be

considered with a view to supplementing rather than replacing oil production on a good production practice base.'"

In its evaluations of water injection, however, Shell chose to use prorated rates rather than the existing GPP rates. At the request of the Board, Shell subsequently provided a third water flood evaluation using GPP rates.

Views of the Board

The Board continues to hold the view that for conservation reasons the Olds Wabamun A Pool, if it remains on primary depletion, should be granted an increased oil production rate as an element of GPP. Should enhanced recovery operations be undertaken, the Board believes that they should also be accorded the benefit of the higher production rates otherwise they would be subject to a serious economic disadvantage.

CONCURRENT PRODUCTION OF THE NORTH-EAST GAS CAP

Views of the Interveners

Neither the Board staff nor the other interveners made specific reference to the question of whether or not the gas cap located in and near Section 34, Township 33, Range 2 West of the 5th Meridian (called the north-east gas cap) would be produced concurrently with the oil accumulation.

Both the Board staff and Shell used the pool configuration depicted by the McCord model and characterized by very limited communication between the north-east gas cap and the main gas cap. The Board staff's prediction assumed that gas wells in the north-east gas cap would not be produced and also that coning of gas cap gas into oil wells in the region would be minimized. On the other hand, Shell's prediction for primary GPP indicated relatively high gas cap production through gas coning into the oil wells in the vicinity of the north-east gas cap.

BP implied by its comments that it intends to seek approval of the production of the gas well in Legal Subdivision 10 of Section 34, the main gas well in the north-east gas cap.

Views of the Board

Decision Report 68-11 is not definitive with respect to the matter but implies that the north-east gas cap should not be produced. The Board's view concerning it may be inferred from the following Board conclusion:

"It also agrees that losses would be reduced by confining gas withdrawal points to areas remote from the oil zone, but believes it proper to require it only to the extent that would not cause undue hardship to the gas unit."

In order to predict reserves of oil and gas by different depletion methods, it is necessary to make basic assumptions regarding gas production from the north-east gas cap. The Board notes that the McCord model has indicated a measure of communication between this gas cap and the oil accumulation, whereas it indicates fairly effective separation between it and the main gas cap. Reviews of the McCord history match suggest that the north-east gas cap is somewhat larger than provided for in the McCord model used by the Board staff. In view of this and having regard for proximity to the oil accumulation of potential withdrawal points in the north-east gas cap, the Board expects that concurrent production of the north-east gas cap would have important effects on the oil recovery. Since approval of concurrent production has not been applied for or granted at this time, the Board believes that it is proper to base oil accumulation predictions on the assumption that the north-east gas cap will remain shut in. Should an application be made for approval of a scheme for concurrent production of the north-east gas cap, the impact on recoveries and correlative rights would have to be carefully considered.

STUDIES PERFORMED

Board Staff

The Board staff used a Scientific Software Corporation reservoir simulation system to predict future performance under primary depletion, updip water fence and downdip water flood combined with a partial water fence. Water injection rates were 6,000 barrels per day for the simple water fence and 7,000 barrels per day for the downdip water flood combined with a partial water fence. A two dimensional, three phase model was used, with grid sizes of one-half mile by one mile in the oil accumulation increasing to one mile by one mile in the main gas cap.

Since it did not perform any history matching runs, the Board staff adopted the overall pool configuration and permeability distribution as depicted by the McCord studies. It also employed porosity and fluid property data similar to that used in the McCord studies. For each prediction, the program option assuming uniform dispersion of fluids in each grid block was adopted.

In the predictions, it was assumed that the gas wells in the north-east gas cap would not be produced. Also, the high gas-oil ratio (GOR) oil wells (those in Legal Subdivision 10 of Section 22 and Legal Subdivision 10 of Section 33) adjacent to this area were not produced. The high productivity oil wells in Legal Subdivision 10 of Section 15 and Legal Subdivision 10 of Section 22 were operated at about twice the rate of the remaining six oil wells.

In its economic predictions made subsequent to the hearing and made available to the interveners, the Board staff used basic operating costs, product prices and capital expenditures derived mainly from the Shell submissions. While the Board staff predicted that gas produced with oil would range up to about 57 billion cubic feet (Bcf), the gas production used in its economic evaluations was from 42 to 30 Bcf reflecting only solution

gas production. The Board staff adopted this approach to economic evaluations on the premise that gas cap gas not recovered at oil wells will be recovered at wells in the gas cap areas, and, as a result, variations in solution gas recovery from one case to another represents the only valid gas income variant for oil accumulation operators.

Shell

Shell's primary depletion predictions were made using the updated McCord model. The McCord system and pool model were considered in detail in connection with Decisions 68-11 and 68-12. In the primary GPP case, the oil accumulation gas production rate was allowed to escalate to high levels early in the remaining life primarily as a result of substantial amounts of gas produced with oil from wells in Legal Subdivision 10 of Section 27 and Legal Subdivision 10 of Section 33. As a result, the cumulative gas produced with oil under this scheme reached 73 Bcf of which about 45 Bcf was subsequently estimated to be solution gas and 28 Bcf gas cap gas.

Shell's water flood and gas flood predictions were based upon an incompressible, stratified flow concept assuming pressure maintenance of the oil accumulation. Shell made predictions for updip water injection based on injection rates of 5,000 barrels per day (assuming 50% effectiveness and prorated crude oil rates), 9,000 barrels per day (assuming 25% effectiveness and prorated crude oil rates) and 13,000 barrels per day (assuming 25% effectiveness and GPP crude oil rates). It considered only a scheme of updip water injection along the gas-oil contact since it regarded downdip injection as probably being an ineffective means of oil recovery. Its predicted gas recovery from the oil accumulation under updip water injection was of the order of 10 Bcf, a value consistent with its assumption of full pressure maintenance of the oil accumulation.

Amerada

Amerada used the Intercomp two dimensional, three phase reservoir simulator to evaluate invasion into the gas cap of water injection along the southern part of the gas-oil interface. It investigated water injection rates of 3,000 and 6,000 barrels per day.

THE TECHNICAL AND ECONOMIC FEASIBILITY OF VARIOUS RECOVERY SCHEMES

More than one set of recovery predictions and economic estimates for each case were introduced by the Board staff and Shell prior to and during the proceeding. For the purpose of the text which follows, the Board has referred to the final set of estimates submitted for each case believing they closely represent the views finally held by each estimator. (A summary of the results of each relevant case as interpreted by the Board staff, Shell and the Board is shown in Table No. 1 attached hereto).

REFERENCE CASE (Primary Prorated)

Views of the Board Staff

The Board staff predicted remaining reserves of oil of 2.6 million STB and gas produced with oil of 49 Bcf if the oil accumulation were prorated and continued to operate under primary depletion. The Board staff estimated that 39 Bcf of the gas produced with oil would be solution gas, and this amount of gas was used in the calculations of present value profit from oil producing operations of $3.3 million.

Views of Shell

For the primary prorated case, Shell predicted a remaining oil recovery of 2.6 million STB and remaining recovery of gas produced with oil of 42 Bcf which resulted in a present value profit of $2.3 million.

Views of the Board

The Board notes that remaining reserves predicted by the Board staff and Shell are very similar. Therefore, for the reference case, the Board adopts remaining reserves of oil of 2.6 million STB and of gas produced with oil of 40 Bcf. Since these volumes are very similar to those submitted, the Board concludes that a suitable present value profit for the reference case would be about $3 million.

CASE A (Primary GPP)

Views of the Board Staff

The Board staff predictions showed that a remaining oil recovery of 4.2 million STB and 57 Bcf of gas produced with oil would occur at the current GPP rate of about 1500 barrels of oil per day. The Board staff concluded that of the 57 Bcf only 42 Bcf should be recognized in determining present value profit. The present value profit was calculated to be $5.6 million.

Ancillary to the Board staff studies was an investigation of crude oil recovery increase (or decrease) as a function of allowed oil production rate. The additional predictions made by the Board staff showed that the incremental oil recovery gain tended to level off at oil production rates beyond 2,000 barrels per day. Increasing the oil production rate from 1,500 barrels per day (near the present GPP rate) at a level of 2,000 barrels per day might yield an additional oil recovery of 0.2 million STB using Board staff trends.

Views of Shell

Shell's predicted remaining recovery of 3.8 million STB crude oil and 73 Bcf gas produced with oil yielded a present value profit of $8.9 million.

The relatively high amount of gas produced with oil resulted from substantial coned gas cap gas. Shell estimated subsequent to the hearing that about 45 Bcf of the gas produced with oil would be drived from produced solution gas.

Shell's views regarding the relationship between rate of oil production under primary GPP operation and ultimate oil recovery were expressed in answer to questions at the hearing. Shell stated that, although present oil productive capacity is about 3,000 barrels per day, the capacity would decline rather rapidly reaching a level of the present GPP rate limit by 1974. Shell expressed a belief that, under primary depletion, by producing crude oil at full capacity from the present day forward, the additional gain in oil recovery would be much less than 1 million STB compared to continued operation within the present GPP rate limit.

Views of the Board

The Board observes that under the presently authorized oil production rates for primary GPP, the ultimate oil recovery predicted by the Board staff is similar to that predicted by Shell. The Board accepts these predictions as being equally valid and, therefore, expects that ultimate oil recovery under primary GPP would be 4 million STB or 1.4 million STB more than would be obtained under primary prorated operation. Respecting the possible additional gain in oil recovery that might be obtained under primary depletion if the permitted oil rate production were increased above the present GPP rate limit, the Board concludes, on the basis of the Board staff's evidence and Shell's testimony, that the additional available oil production capacity over and above the present GPP rate limit would be short-lived and that possible gains in oil recovery would be modest relative to the near term additional impact on the proration plan.

An important influence on the present value profit predictions for primary GPP are the rates and overall quantity of gas cap gas produced through oil wells in Legal Subdivision 10 of Section 27 and Legal Subdivision 10 of Section 33, both in Township 32, Range 2 West of the 5th Meridian. Production of substantial quantities of gas cap gas at those wells would cause depletion of the north-east gas cap. The Board believes that such depletion would not be in the interest of conservation nor would it be reasonable from a correlative rights point of view. The Board, therefore, believes that the Shell predictions must be so adjusted as to reflect minimized gas cap gas coning at oil wells, and has included in its prediction of gas production only the oil accumulation solution gas plus a modest amount of gas cap gas that would be coned into the oil wells under normal oil production operations. The Board believes a reasonable estimate for gas produced with oil to be 55 Bcf made up of 45 Bcf solution gas and 10 Bcf coned gas cap gas. Using this amount of gas and adopting a remaining oil recovery of 4 million STB, the Board expects that the present value profit for primary GPP would be about $7 million.

CASE B (Water Fence)

Views of the Board Staff

The Board staff reservoir simulation predictions for the water fence case assumed injection of water at a maximum of 6,000 barrels of water per day into two wells at the southern part of the gas-oil contact. The predictions showed a significant gain in oil recovery compared to both primary prorated and primary GPP.

The Board staff contended that the gain in oil recovery resulted primarily from the restriction of the flow of gas from the oil accumulation toward the main gas cap, thereby retaining additional energy for oil production. It concluded that actual water flooding would occur in only a small portion of the oil accumulation. As a result, total gas produced with oil is the same amount as that resulting under primary GPP. The Board staff acknowledged that owing to water invasion there would be losses of otherwise recoverable gas from the main gas cap of about 10 to 15 Bcf.

The Board staff calculated a present value profit for the water fence case of $5.3 million based on oil recovery of 6.2 million STB and assigned gas recovery of 38 Bcf. Thus, the Board staff water fence predictions indicated an incremental gain in oil recovery of 3.6 million STB, an incremental reduction in overall pool gas recovery of 10 to 15 Bcf and an incremental gain in present value profit of $2 million relative to the reference case.

Views of Shell

Shell's approach was to develop a fully effective water fence that would serve the dual purpose of isolating the oil accumulation from the gas cap and, also, of fully maintaining pressure in the oil accumulation. In its estimates for water flood at present GPP oil production rates, Shell predicted remaining oil recovery of 4.9 million STB and oil accumulation gas recovery of 9 Bcf. In this case Shell assumed that only 25 per cent of the injected water contributes to oil accumulation pressure maintenance and, as a result, 13,000 barrels per day of water injection is required to effect pressure maintenance of the oil accumulation. Owing to large capital and operating costs and because of low gas recovery, the venture would be uneconomic resulting in a loss of $0.6 million in present value profit. Thus, comparing the Shell predictions for water fence GPP to primary prorated, there would be an incremental gain in oil recovery of 2.3 million STB, an incremental loss in gas produced with oil of 33 Bcf and an incremental reduction in present value profit of $2.9 million.

Shell drew attention to certain additional risks of the water fence scheme, which it had not accounted for in its predictions, but, which would further derogate from the scheme. Shell indicated that with current technology it would not be economically feasible to install oil well lifting equipment to withstand the extreme corrosion conditions induced by the presence of water in the high hydrogen sulphide environment in the Olds Wabamun A Pool. It

believed that a similar condition might apply for gas lift equipment and the result could be premature abandonment of the pool if placed on water flood. Shell also referred to a loss of gas cap recovery of 35 Bcf (interpreted from Board staff predictions) as being a further detrimental effect of the scheme.

Views of BP

BP expressed concern that a water fence scheme might lead to water breakthrough to the gas well in Legal Subdivision 10 of Section 34.

Views of Amerada

Amerada performed reservoir simulation studies involving the injection of water at the gas-oil interface which led it to the conclusion that there would be no adverse effects on the main gas cap resulting from injection of water along the gas-oil interface.

Views of the Board

The Board is inclined to agree with the position taken by its staff that the water fence should be limited to the southern part of the gas-oil contact (which the Board refers to as a partial water fence), thereby separating the main gas cap and the oil accumulation in the region of main potential fluid migration. If a partial water fence scheme were implemented, the Board believes that the remaining oil recovery would approach 6 million STB and the remaining total recovery of gas produced with oil would be about 50 Bcf. The Board expects that the present value profit for this type of scheme would be about $5 million. Having regard for all the predictions, the Board believes that losses of otherwise recoverable gas cap gas might be 5 to 10 Bcf owing to water invasion into the main gas cap from the partial water fence.

Based on its own approximations, the Board concludes that a water fence as proposed by the Board staff, would result in incremental gains of oil recovery of 3.4 million STB, gas produced with oil of 5 Bcf and present value profit of $2 million relative to the reference case. On this basis it appears that a reasonably designed water fence scheme would be economically justified. An additional test to be applied is whether it would provide significant improvement over recoveries obtainable under primary GPP. From this viewpoint, a water fence scheme as proposed by the Board staff would probably yield an incremental increase in oil recovery of 2 million STB whereas it would cause an overall reduction in gas recovery from the total pool of 10 to 15 Bcf relative to primary GPP, consisting of 5 to 10 Bcf gas cap gas and some 5 Bcf oil zone gas. In other words, losses in gas recovery would to some extent offset the gains in oil recovery. The Board therefore concludes that the water fence scheme as proposed by the Board staff would provide limited improvement in hydrocarbon value while posing operating risks to both the oil accumulation and gas cap.

DOWNDIP WATERFLOOD COMBINED WITH PARTIAL WATER FENCE

Views of the Board Staff

Subsequent to the hearing, the Board staff performed an additional water flood prediction utilizing four injection wells distributed along the oil accumulation in a downdip position and one injection well in the southern part of the gas-oil contact. Results of the predictions conveyed in the Board staff compilations made available on January 4 and January 8, 1971, showed remaining recoveries of 8.5 million STB crude oil, 38 Bcf gas produced with oil (of which 30 Bcf is recognized for economic evaluations) and present value profit of $7.3 million. Incremental recoveries relative to the reference case were an increase of 5.9 million STB oil and a decrease of about 10 Bcf of gas produced with oil. Present value profit increased by $4.0 million relative to the reference case.

Views of Shell

Shell contended that downdip water injection was not feasible because continual loss of reservoir energy to the gas cap would occur, and, also, an inordinate number of water injection wells would be needed because of low permeability of the downdip region of the oil accumulation. In meetings with the Board, Shell expressed the view that the Board staff predictions were generally optimistic owing for example to selction of grid sizing, assigned water handling costs and water injection start up time.

Views of the Board

The Board believes that the Board staff predictions, even though not performed rigorously, indicate the probability of substantial additional recovery of oil through a suitably designed scheme of downdip water flooding combined with a partial water fence. Moreover, it appears that such a scheme could be designed to minimize the degree of risk of gas cap losses by water invasion. Although the Board staff predictions incorporated some assumptions which may make results optimistic, the Board believes other assumptions used may render the results pessimistic. In the opinion of the Board, predictions in excess of some 8.5 million STB might have resulted if an optimum scheme had been developed. The Board holds the opinion that water flood experience in not unlike situations such as the Westward Ho Rundle Pool tend to confirm that suitably designed water floods may provide substantial recovery improvements in low permeability carbonate reservoirs. The risks of excessive corrosion and of gas cap losses, nevertheless, would be present for any water injection scheme applied in the Olds Wabamun A Pool. These risks would have to be taken fully into account in a carefully designed water flood scheme.

The Board believes that a suitable water flood scheme if implemented in the Olds Wabamun A Pool could yield an incremental gain in oil recovery of 4 to 5 million STB with an incremental reduction of perhaps 15 Bcf in gas recovery relative to recoveries obtainable under primary GPP. The Board concludes that a water flood scheme should be implemented since it would lead to an overall significant improvement in conservation relative to primary GPP and would be economically attractive relative to the reference case.

Summary of Board Views

The Board believes that in deciding whether enhanced recovery operations are warranted in the Olds Wabamun A Pool, comparison of recoveries and economics should be made with primary prorated operations. Nonetheless, the Board would not expect the operators to institute enhanced recovery operations unless there was a significant increase in recovery over that obtained by primary GPP.

With respect to the present GPP status, the Board believes that since, for conservation reasons, it would continue to assign the existing GPP rate if the oil zone remained on primary depletion, enhanced recovery operations must be permitted on the same basis if conservation is to be achieved.

The studies made by the Board staff and Shell demonstrate that oil recovery would be significantly increased by water flood operations. The Shell studies indicate that the gain in oil recovery would be almost completely compensated by losses in gas recovery and that water flood operations would be conducted at a financial loss. In contrast to this position the Board staff predicted substantially higher oil recoveries than Shell with only a limited reduction in gas recovery and a scheme that was financially more attractive than either primary prorated operations or the current primary GPP operations.

After assessing these two widely differing positions the Board concluded that:

1. the Board staff studies confirmed that significant improvement in oil recovery would be obtained by a combination downdip water flood and a partial water fence and that oil recoveries would be in the order of those predicted by the Board staff,

2. the Shell studies have seriously overstated the impact of water flood operations on gas recovery and that gas recovery will approximate the Board staff estimates.

On the basis of these broad conclusions, the Board believes that it is reasonable to adopt oil and gas recoveries under water flood operations that would yield an incremental oil recovery of some 4 to 5 million barrels over the current primary GPP or some 5 to 6 million barrels over primary prorated. The decrease in gas recovery would be some 10 to 15 billion cubic feet including both oil zone gas and gas cap gas. The Board believes that these recoveries would result in a larger present value profit for enhanced recovery operations than for primary prorated operations. Consequently, the Board believes that enhanced recovery operations should proceed as quickly as possible in order to maximize recovery from the pool.

The Board recognizes even though recoveries may be substantially increased that the present value profit under the enhanced recovery operations may be less than under the current primary GPP operations. Should this be the case, the Board can appreciate the reluctance of the operators to convert to a depletion method that is prospectively less profitable and entails added risks. However, having regard for the background in granting GPP in the Olds

Wabamun A Pool and the matters of policy enunciated in this report, the Board cannot accept that a reduction in profitability from primary GPP should negate the recovery of additional oil and gas. In fact, the Board believes that as long as the profitability is greater than that obtained under primary prorated operations and the risks have been properly allowed for, enhanced recovery operations should proceed.

DECISION

On the basis of all the information made available in connection with Proceeding No. 5124 and subsequent to it, the Board is satisfied that overall hydrocarbon recovery from the Olds Wabamun A Pool can be significantly improved by appropriate enhanced recovery operations.

Accordingly, in order to prevent waste, unless the Board

(a) decides after the filing of a detailed study by September 1, 1971, that enhanced recovery operations are not feasible, or

(b) receives a suitable application by September 1, 1971, to implement an enhanced recovery scheme in the Olds Wabamun A Pool by February 1, 1972,

it will seek the approval of the Lieutenant Governor in Council to require enhanced recovery operations in the Olds Wabamun A Pool on or before February 1, 1972.

OIL AND GAS CONSERVATION BOARD

A. F. Manyluk
Deputy Chairman

DATED at Calgary, Alberta
March 25, 1971

CLDS WAB_ [illegible] A POOL

Proceeding No. 5124

Table No. 1

Remaining Recoveries, Investments and Profits from Jan. 1, 1971	Reference Case Primary Prorated			CASE A Primary GPP			CASE B Waterfence GPP			CASE C Downdip Water Flood With Partial Water Fence GPP		
	Board Staff	Shell	Board	Board Staff	Shell	Board	Board Staff	Shell	Board	Board Staff	Shell	Board
Crude Oil (MMSTB)	2.6	2.6	2.6	4.2	3.8	4	6.2	4.9	6	8.5	No Prediction-Used Board Staff Values for Economic Appraisal	8 to 9
Gas Produced with Oil (Bcf)	49 *39	42	45	57 *42	73	55	57 *38	9	50	38 *30		40
Capital Investment ($ Millions)	Nil	Nil		.3	.3		1.7	2.8		2.3		
Present Value Profit Before Tax ($ Millions)	3.3	2.3	3	5.6	8.9	7	5.3	(0.6)	5	7.3	7.0	7

*Recovery of gas produced with oil used for economic evaluations (Bcf)

**Present value profit before tax determined using a discount factor of 6%

OIL AND GAS CONSERVATION BOARD

Decision 71-5
Application No. 5589
Report to The Lieutenant
Governor in Council

IN THE MATTER OF AN APPLICATION OF
IMPERIAL OIL LIMITED UNDER
THE GAS RESOURCES PRESERVATION ACT

THE APPLICATION AND HEARING

Imperial Oil Limited on behalf of itself and certain other producers of oil from the Boundary Lake South Triassic E Pool applied for a permit authorizing the removal from the Province of all gas produced from the pool. The gas would be produced in association with the production of crude oil from the pool and the permit would be for a total amount not to exceed 17.9 billion cubic feet.

The application was heard on March 23, 1971, by the Board with A. F. Manyluk, P. Eng. and Vernon Millard sitting.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Imperial Oil Limited	F. W. Kelly R. D. Knowles, P. Eng. R. J. Craig	Imperial
Board Staff	G. A. Warne, P. Eng.	

There were no interventions respecting the application.

SUBMISSION OF IMPERIAL

Imperial submitted that pursuant to an agreement with Amoco Canada Petroleum Company Ltd., it proposes to construct and operate a two-phase pipe line facility from the Boundary Lake South Field to connect with crude oil handling facilities and the Boundary Lake South Conservation Plant on the British Columbia side of the Alberta-British Columbia boundary. The two companies between them control 80 per cent of the petroleum and natural gas rights and a similar percentage of the anticipated production from the Boundary Lake South Triassic E Pool. It

added that unit preparations have begun to establish a pool-wide unit which would include the properties of the holders of the remaining 20 per cent of the pool. Imperial has obtained an order from the National Energy Board, a copy of which it included with its submission, permitting it to construct the main pipe line which will consist of approximately seven miles of 10.75 inch outside diameter line beginning from a point in Alberta in Legal Subdivision 3 of Section 23, Township 84, Range 13 West of the 6th Meridian to a point in British Columbia in Legal Subdivision 8 of Section 2, Township 85, Range 14 West of the 6th Meridian. The line would be the property of and be operated by Imperial but Imperial would use it to transport oil and gas, in a two-phase system, belonging to the other owners in the pool as well as its own oil and gas.

Imperial submitted that the gas reserves of the pool were some 17.9 billion cubic feet and that gas production from the pool would gradually increase to some 6 million cubic feet per day in 1973. It stated that if maximum daily and maximum annual rates appear necessary in any permit issued it would be reasonable to prescribe rates of 6 million cubic feet per day and 2.2 billion cubic feet per year. It further agreed that it would be satisfactory to limit the permit term to 25 years.

Imperial stated that there is presently no suitable battery facility or processing plant available for the gas on the Alberta side of the border. There is capacity at the nearby processing plant in British Columbia to process all gas production except part of the peak gas production from the Boundary Lake South Triassic E Pool. It added that the proposed method of disposition was the most efficient and economic method of producing, handling and conserving oil and gas from the Boundary Lake South Triassic E Pool and that there was no economic means of processing and disposing of the gas in Alberta. It entered a letter dated March 22, 1971 from Westcoast Transmission Company Limited indicating the company's willingness to take the residue gas resulting from processing of the gas considered in the application.

Imperial submitted that the gas reserves considered are surplus to provincial requirements since the growth in reserves in the Province since the Board's last finding on this matter in August, 1970, must exceed increased provincial requirements. Further, most of the reserves with which the application is concerned have been developed since that time.

Imperial asked that the Board omit the usual conditions of permits that local markets be given first priority since the gas would not be available in a marketable condition in Alberta and since the nearest Alberta Gas Trunk Line facilities were about five miles north of the starting point of the pipe line.

FINDINGS OF THE BOARD

The Board finds that under the present circumstances it is not reasonable to require that the gas produced along with oil from the Boundary Lake South Triassic E Pool be separated from the oil and processed to a marketable condition in Alberta nor does it appear reasonable to require that the gas be transported from Alberta in a pipe line separate from the oil. It is not presently economically feasible to use the gas to serve local Alberta communities and, having regard for the volumes involved, to have Alberta Gas Trunk Line Company Limited transport the gas within Alberta.

The Board is satisfied that the gas reserves for which a permit is sought are available to the applicant.

It finds that the gas reserves are surplus to Alberta requirements. Furthermore, if the applicant were denied a permit to remove the gas from the Province the gas could not be conserved and marketed and hence the reserves available to Alberta markets would not be increased.

Should circumstances change such as to make the separation and processing of the gas in Alberta economically viable, the Board believes that the normal provisions should apply and local markets should be given first priority and the gas should be transported to the Alberta border through the facilities of The Alberta Gas Trunk Line Company Limited. In view of this the Board believes that a provision should be included in any permit issued indicating that the Board may require that the gas be separated from the oil and processed to a marketable condition in Alberta if at any time it appears to the Board that such is a reasonable requirement.

The Board believes that although the gas available from the pool will be produced at rates directly related to the oil production rates, it is reasonable to prescribe in any permit issued the usual term of 25 years, the total permit volume and maximum daily and maximum annual rates of withdrawal. With these provisions any substantial modifications to the scheme for removing the gas from the Province would require a further early application to the Board before being undertaken.

With respect to production reports, the Board concludes that although the gas is to be processed and marketed in British Columbia the applicant should submit to the Board monthly reports showing the volume of gas separated from the oil and the disposition of the gas and by products recovered from the raw gas.

THE DISPOSITION OF THE APPLICATION OF IMPERIAL OIL LIMITED

In the light of its findings and its responsibility

under the Act, the Board is prepared, with the approval of the Lieutenant Governor in Council, to grant a permit of the form shown in Attachment I and subject to the terms and conditions therein contained.

OIL AND GAS CONSERVATION BOARD

Vernon Millard
Board Member

DATED at Calgary, Alberta
April 28, 1971

OIL AND GAS CONSERVATION BOARD

Decision 71-6
Proceeding No. 5400

ANNUAL RESERVES AND PRODUCTIVE CAPACITY

HEARING

A hearing was held by examiners appointed by the Board for the purpose of hearing representations respecting the recoverable reserves of crude oil in those pools listed in Attachment I. In addition, the examiners heard productive capacity presentations on those pools listed in Attachment III.

The hearing was conducted by D. R. Craig, P. Eng.; N. A. Strom, P. Eng.; and J. R. Pow, P. Eng. on February 15 and 16, 1971.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Amerada Hess Corporation	F. Nadir, P. Eng. R. Merrett, P. Eng.	Amerada
Aquitaine Company of Canada Ltd.	J. A. Pope, P. Eng.	Aquitaine
Atlantic Richfield Canada Ltd.	B. H. Wells, P. Eng. M. N. Kinakin, P. Eng. C. W. Demetrick, P. Eng. D. L. Bowman, P. Eng.	ARCO
Banner Petroleums Ltd.	D. W. Barnett, P. Geol. R. W. Evans	Banner
BP Oil and Gas Ltd.	R. G. Kessler, P. Eng. G. Wood	BP
Canadian Superior Oil Ltd.	M. T. Alexander, P. Eng.	Canadian Superior
Gulf Oil Canada Ltd.	M. H. Melnyk, P. Eng.	Gulf
Hudson's Bay Oil and Gas Company Limited	T. Renner	Hudson's Bay
Imperial Oil Limited	F. J. Bagley, P. Eng. R. J. Craig	Imperial
Mesa Petroleum Co.	D. L. Kolesar	Mesa
Pacific Petroleums Ltd.	R. Johnson, P. Geol. R. H. Paul J. Pawelak, P. Eng.	Pacific

APPEARANCES (Cont'd)

	Represented by	Abbreviations Used in Report
Samedan Oil of Canada Inc.	G. Goss F. W. Kelly G. McLeod	Samedan
Shell Canada Limited	T. R. Fountain J. A. Irvine, P. Eng.	Shell
Union Oil Company of Canada Limited	D. S. Paxman, P. Eng. D. F. Duprey	Union
Board Staff	G. H. Stafford, P. Geol. R. G. Evans, P. Eng. C. C. Fortems, P. Eng.	Board

SUBMISSIONS

Included in each submission was the Board's 0-38 form. This provided a convenient means of listing the reservoir factors pertinent to the establishment of pool ultimate reserves. Generally the choice of these factors was discussed in some detail.

For the most part, the submissions relied heavily on volumetric interpretation of subsurface geological data to establish the in-place oil volume with a few being based on material balance considerations.

FINDINGS OF THE EXAMINERS

Ultimate Reserves

The findings of the examiners with respect to the setting of recoverable reserves are tabulated in Attachment I. Attachment II is a comparison of crude oil in place and recoverable oil reserves as proposed by the operator, and those recommended by the examiners. Generally the examiners were in agreement with most of the fluid and rock factors proposed in the submissions. However, for some pools significant differences of opinion did occur and these are discussed by pool in the following paragraphs.

Ricinus Cardium A Pool

The difference in shrinkage factor recommended and the value of .66 as proposed by Pacific is explained by the choice of PVT samples. Comparison of sampling pressure versus measured bubble point pressure and other factors suggested to the examiners that a shrinkage factor of 0.63, derived from the fluid sample taken from the well in Legal Subdivision 7 of Section 18, Township 26, Range 8, West of the 5th Meridian, was the most representative.

Ricinus Cardium D Pool

The examiners agree with Pacific that the primary recovery factor can vary from 6.6 per cent to 14.6 per cent for gas cap to oil accumulation volume ratios of 0 and 1.5, respectively. Since the "m" ratio is unknown a recovery factor of 10 per cent was adopted until additional evidence is available.

Ricinus Cardium F Pool

As the pool is penetrated by only a single well, the arbitrarily assigned acreage of one quarter section seemed appropriate.

Pacific's approach for establishing net pay assumed the entire zone to be sand, and ignored the low porosity indications on the sonic log. The examiners believe this to be optimistic and have decided to assign a net pay of 78 feet rather than the 88 feet proposed.

The high and rapidly increasing gas-oil ratio performance shown by this pool suggested to the examiners that recovery of 15.8 per cent as predicted by Pacific will not be realized. Consequently, a value of 7 per cent has been chosen which reflects both the inferior GOR performance and a higher abandonment pressure than that proposed by Pacific.

Boundary Lake South Triassic E Pool

Imperial's isopach map appeared optimistic for the south end of the pool since the zero isopach was positioned near an abandoned wet well. In addition Imperial included some unsubstantiated area on the east side of the pool. After making adjustments to reduce these uncertainties, the examiners have adopted a rock volume of 100,000 acre-feet based on a pool acreage of 14,500 acres and a net pay thickness of 6.9 feet.

Meekwap D-2 A Pool

Samedan included a substantial amount of unproved acreage in its rock volume estimate of 278,171 acre-feet. The examiners recommend 160,000 acre-feet, which includes all validated acreage plus some probable productive acreage.

The recovery factor of 35 per cent proposed by Samedan represents a provincial average of D-2 Pools including some major reservoirs known to be benefiting from active aquifers. The examiners believe it is premature to conclude that Meekwap D-2 will enjoy a significant natural water drive and on this basis have chosen 30 per cent as a recovery factor.

Red Earth Slave Point A Pool

The rock volume of 89,597 acre-feet as proposed by Union appears overly optimistic to the examiners in a number of areas. Union carries its isopaching out to and beyond the pool boundaries which does not seem to be fully justified in this case. Furthermore, the operator assigned

35 feet of pay to the zone at the well in Legal Subdivision 12 of Section 5, Township 88, Range 8, West of the 5th Meridian on the basis of its microlog interpretation. Upon a close examination of the sonic log, this zone appeared to have only 17 feet of effective pay. Taking these corrections into account suggested a rock volume of 60,000 acre-feet, a value adopted by the examiners.

The examiners believe the flash liberation curve from PVT analysis rather than the differential should be used to evaluate the shrinkage factor. On this basis a shrinkage factor of 0.93 was adopted.

In view of the limited transmissibility in this reservoir the examiners have proposed primary recovery of 7 per cent as opposed to the 14 per cent suggested by Union.

Nipisi Gilwood C Pool

In mapping the oil section rock volume of the Nipisi Gilwood C Pool, Banner extended the isopachs liberally to the south-west and east. This yielded a rock volume of about 63,000 acre-feet. In contrast the examiners have restricted the oil section to 45,000 acre-feet, the volume established by drilled wells.

Virgo Keg River AA Pool

In predicting recovery from the pool, Atlantic used a 30 foot sandwich loss, a 30 per cent residual oil saturation and a 90 per cent conformance factor to derive a recovery factor of 46 per cent. The examiners believe the sandwich used and porosity used in the flushing calculation were somewhat optimistic. Having regard for this evaluation and for the recovery factor established for other similar reservoirs in the Virgo area, the examiners decided to recommend a recovery factor of 40 per cent for the pool.

Zama Keg River K2K Pool

Mesa recommends continued assignment of a 25 per cent recovery factor. The examiners recognize that this is a recovery which would be estimated using the Board standard approach to the Zama area pool. However, the single well in the pool has produced about one per cent of the estimated oil in place, is completed near the top of its pay section and yet is exhibiting a high and increasing water-oil ratio. The examiners concluded that recovery from the pool will be limited by performance of the well and on this basis have assigned a recovery factor of 10 per cent.

Productive Capacity

The examiners have reviewed the productive capacity submissions and recommend only minor changes in a few instances so that the values given will be consistent with the definitions used by the Board. The recommendations are shown in Attachment III.

RECOMMENDATIONS OF THE EXAMINERS

The examiners recommend that the reserve factors and the reserves listed in Attachment I be adopted.

VIEWS OF THE BOARD

The Board agrees with the recommendation of the examiners.

DECISION

The Board has adopted the reserve factors and reserves listed in Attachment I. These reserves will be in effect May 1, 1971.

OIL AND GAS CONSERVATION BOARD

G. W. Govier
Chairman

DATED at Calgary, Alberta
April 13, 1971

ATTACHMENT I

RESERVE FACTORS - POOLS AT FEBRUARY 1971, RESERVES HEARING

POOL	AREA Acres	PAY THICKNESS Feet	POROSITY Fraction	WATER SATURATION Fraction	OIL SHRINKAGE FACTOR Fraction	INITIAL OIL IN PLACE MSTB	POOL RECOVERY PRIMARY Fraction	POOL RECOVERY ENHANCED Fraction	RECOVERABLE OIL PRIMARY MSTB	RECOVERABLE OIL ENHANCED MSTB	RECOVERABLE OIL TOTAL MSTB
CARDIUM											
Ricinus Cardium A	1,425	37.0	.130	.12	.63	29,500	.13		3,840		3,840
Ricinus Cardium D	1,040	38.5	.085	.20	.71	15,000	.10		1,500		1,500
Ricinus Cardium F	160	78.0	.100	.16	.73	5,940	.07		416		416
Ricinus Cardium H	160	104.0	.095	.18	.71	7,140	.08		571		571
TRIASSIC											
Boundary Lake South Triassic E	14,500	6.9	.160	.14	.78	83,300	.10		8,330		8,330
Kaybob South Triassic A	5,200	27.9	.110	.11	.71	78,200	.15		11,700		11,700
RUNDLE											
Crossfield Rundle E	1,640	15.2	.120	.20	.76	14,200	.05		708		708
NISKU (D-2)											
Meekwap D-2 A	4,280	37.4	.091	.15	.74	71,000	.30		21,300		21,300
LEDUC (D-3)											
Innisfail	7,530	77.0	.060	.13	.53	124,000	.60		74,400		74,400
Stettler	4,600	26.1	.061	.17	.82	38,700	.60		23,200		23,200
BEAVERHILL LAKE											
Ante Creek Beaverhill Lake	3,550	12.8	.057	.25	.65	9,800	.25		2,450		2,450
SLAVE POINT											
Red Earth Slave Point A	3,970	15.1	.090	.25	.93	29,200	.07		2,040		2,040
GILWOOD											
Nipisi Gilwood C	3,600	12.5	.124	.35	.83	23,400	.20		4,680		4,680
KEG RIVER											
Virgo Keg River AA	62	156.0	.073	.24	.87	3,600	.40		1,440		1,440
Zama Keg River K2K	157	64.2	.054	.20	.89	3,000	.10		300		300

ATTACHMENT II

COMPARISON OF OIL IN PLACE AND RECOVERABLE RESERVES

(Thousand of Stock Tank Barrels)

Pool	Operator N	Operator U	Examiners N	Examiners U
Ricinus Cardium A	31602	3729	29500	3840
Ricinus Cardium D	13434	1746	15000	1500
Ricinus Cardium F	6199	979	5930	415
Ricinus Cardium H	6768	893	7140	571
Boundary Lk S Triassic E	96400	10600	83300	8330
Kaybob S Triassic A	81770	12266	78200	11700
Crossfield Rundle E	15185	759	14200	708
Meekwap D-2 A	129021	45157	71000	21300
Innisfail D-3	124500	75000	124000	74400
Stettler D-3 A	40511	26332	38700	23200
Ante Creek BHL B	9800	2666	9800	2450
Red Earth Slave Point A	43834	6136	29200	2040
Nipisi Gilwood C	32176	6435	23400	4670
Virgo Keg River AA	3600	1660	3600	1440
Zama Keg River K2K	3000	750	3000	300

ATTACHMENT III

PRODUCTIVE CAPACITY

(Stock Tank Barrels per Day)

(1) Pool	(2) Peak MER Capacity	(3) Column (2) Adjusted for Developed Well-Head Capacity	(4) Column (3) Adjusted for Field and Proc[illegible] Facility Limit[illegible]
Ante Creek Beaverhill Lake	1,700	1,700	1,500
Bellshill Lake Blairmore	10,000	4,500	4,500
Carson Creek North Beaverhill Lake A & B	50,000	45,000	25,000
Erskine D-3	2,500	2,500	1,900
Ferrier Cardium E	4,450	2,300	1,700
Harmattan Elkton Rundle C	14,500	14,500	5,000
I.S. #3 (Zama-Virgo, 25 Pools)	7,900	5,500	5,500
Joffre D-2	15,000	15,000	9,900
Leduc Woodbend D-3 A	23,000	23,000	23,000
Provost Viking C	11,650	5,170	5,170
Rainbow Keg River EEE	5,500	5,500	5,500
Rainbow South Keg River B	5,800	5,800	2,640
Rainbow South Keg River E	7,000	3,600	3,600
Red Earth Granite Wash A	4,300	2,950	2,950

OIL AND GAS CONSERVATION BOARD

Decision 71-7
Application No. 5550

Concurrent Production From the
Westerose D-3 Pool

THE APPLICATION AND HEARING

Gulf Oil Canada Limited applied for permission to concurrently produce oil and gas cap gas from the Westerose D-3 Pool, submitting that a gas cap withdrawal at rates up to 15 MMCFD was necessary to stabilize the oil-water contact in the pool to prevent further residual oil losses into the aquifer.

Texaco Exploration Canada Limited intervened in the application claiming that the Working Interest Owners of the Westerose D-3 Pool should be required to compensate for gas-cap production with water injection if gas-cap production indicated detrimental effects on ultimate recovery of any of the other D-3 pools in the trend. It also contended that Gulf had over-estimated the effect on the Westerose D-3 Pool of cycling in the Bonnie Glen D-3 Pool.

Imperial Oil Limited intervened for purposes of cross-examination only.

The application was heard on March 24, 1971, by the Board members G. W. Govier, P. Eng.; A. F. Manyluk, P. Eng.; and V. Millard.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used In Report
Gulf Oil Canada Limited	T. E. Randall, P. Eng. M. J. Melnyk, P. Eng. Dr. D. Wroe	Gulf
Texaco Exploration Canada Ltd.	D. A. Nikiforuk, P. Eng. R. J. Gasper, P. Eng.	Texaco
Imperial Oil Limited	D. Bossler, P. Eng.	Imperial
Board Staff	R. G. Evans, P. Eng. C. C. Fortems, P. Eng. J. W. Wasson, P. Eng.	Board Staff

DEFINITION OF ISSUES INVOLVED

The Westerose D-3 Pool is located in the Acheson-Homeglen-Rimbey chain of ten D-3 Pools which extends southwesterly from a point near Edmonton for a distance of over seventy miles. These pools are all in

communication through the underlying Cooking Lake aquifer. The Westerose D-3 Pool consists of a large accumulation of oil overlain by a gas cap, and in good communication with the aquifer. To the immediate south of Westerose are Westerose South (a gas pool under production) and Homeglen Rimbey (an oil and gas pool under concurrent production) while to the immediate north is Bonnie Glen (a large oil pool under production).

The major issue in the application is the significance of interface stability on ultimate recovery. Interface stabilization could be achieved by the following techniques, increased oil zone production, water injection, solvent flooding coupled with water injection, gas-cap cycling, or by controlled gas cap production.

Another issue, arising from the interconnection through the aquifer of pools to the north and the south of the Westerose D-3 Pool, is the possible effect of the application on the other pools and the responsibility of the operator in one pool for pressure response in other pools.

The methods of interface observation, including the frequency of measurement and the number of wells required for observation, are further matters of importance.

These matters are discussed under the headings:

(a) Interface Stabilization and Recovery
(b) Multi-Pool Considerations
(c) Methods of Observation

INTERFACE STABILIZATION AND RECOVERY

The applicant based its proposal on the concept that the oil-water interface should be stabilized in the interests of optimum hydrocarbon recovery from the Westerose D-3 Pool. The Board agrees with this concept.

(1) Views of Gulf

Gulf's views were based on the results of its two-dimensional model study of the Acheson-Homeglen-Rimbey D-3 trend and the underlying Cooking Lake Aquifer. This study incorporated the assumption that the existing operations would continue in the other pools with the exception of the Bonnie Glen D-3 Pool, which would be subjected to gas cycling commencing on January 1, 1972.

Gulf stated that the best method to attain oil-water interface stability and optimum oil recovery would be to increase oil production. In its views, however, this would require a very significant increase in the oil production rate, and could not be justified within the proration system.

Gulf's study indicated that water injection would result in interface stability as well as an increased oil recovery of 1.0 MMSTB over that realized by gas-cap production. Water injection at rates corresponding to voidage replacement ratios of 1.5:1 and 3:1 were examined. Gulf concluded that a voidage replacement ratio of 3:1, or an approximate injection rate of 45,000 BWPD, would be required to stabilize the interface. On this basis, it contended that water injection was not economic. Gulf also stated that since water injection was not economic, solvent flooding was not feasible.

Furthermore, Gulf contended that gas-cap cycling was not feasible because of early dry gas breakthrough expected, and the enormous investment required to process gas at rates large enough to accomplish the amount of voidage necessary to stabilize the interface.

Gulf concluded that gas-cap production at controlled rates up to 15 MMCFD based on interface measurements was the only practical method to stop the oil-water interface from descending. It proposed an initial gas-cap production rate of some 5 million cubic feet per day, corresponding with the capacity of present facilities.

(2) Views of Texaco

Texaco contended that Gulf should be required to supply computer runs indicating the required gas-cap withdrawal rates in the event that cycling in Bonnie Glen did not occur. Texaco agreed, however, that this would not be necessary if Gulf were prepared to carefully monitor interface movements, and reduce or cease gas cap production as required to maintain a stable oil-water interface.

(3) Views of the Board

The Board agrees that increased oil production from Westerose is not a feasible solution to the problem because of the impact on the proration system. The Board also agrees that water injection and gas cap cycling as outlined by Gulf are not economically justified and therefore not practical alternatives. The Board accepts that solvent flooding is not feasible, since pressure maintenance by water injection would have to be an integral part of any solvent flood scheme.

The Board therefore agrees with Gulf that gas cap production at controlled rates of the order proposed by Gulf is the most practical method within the control of the Westerose operator of stopping the oil-water interface from descending further, and of avoiding irreversible losses in oil recovery that would otherwise occur by invasion and spreading of oil into the underlying aquifer. The Board agrees with Gulf and Texaco that gas cap production should be closely controlled based on interface observations, so as to ensure stabilization of the oil-water interface.

MULTI-POOL CONSIDERATIONS

(1) Views of Gulf

In response to questioning by Imperial, Gulf agreed that historically each operator has accepted the responsibility only to control

pressure in its own part of the aquifer for the benefit of the recovery from its own pool. Gulf emphasized that practicality and economic feasibility are important considerations for any scheme implemented in a pool.

(2) Views of Texaco

In response to questioning by Gulf, Texaco stated that through monitoring actual performance, any interference among the interconnected pools should be clearly indicated. Furthermore, Texaco indicated that replacement of gas cap withdrawals from Westerose by water injection would theoretically be beneficial to Bonnie Glen.

In response to Imperial's question, Texaco agreed that where a pool is produced under normal operation, each operator accepts only the responsibility for taking the necessary action to control the pressure in its own pool. Texaco did however, state that the blowdown of a gas-cap or withdrawals from a gas cap are not really normal operations. Texaco mentioned that the two major D-3 pools south of Westerose are being produced as gas pools, and that this constitutes, in Texaco's interpretation, a normal operation. It contended that when an operation which is not normal is contemplated, it should be examined to determine whether it would have any adverse effects on any interconnected pool.

(3) Views of the Board

The Board agrees that, under normal conditions and in the absence of an inter-pool operating scheme, the responsibility of an operator for pressure maintenance extends only to the pool in which he is the operator and not to interconnected pools. The production plan proposed by Gulf involving gas cap production only to the extent required for oil-water interface stabilization is not one which in the Board's opinion should, impose upon Gulf any responsibility for the pressure behaviour in other pools.

Notwithstanding the above, the Board recognizes that situations could occur, in a group of interconnected pools, where the optimum recovery of hydrocarbons may not result if the pools are operated completely independently. Some of the interconnected pools in the Acheson-Homeglen-Rimbey D-3 reef chain may well be such a group. In such a situation the Board believes it has a responsibility to determine whether there is a practical and economical method of integrated operation which would lead to recoveries significantly greater than by independent pool production methods. Where the ownership interests are different in the pools affected, integrated operations could, and probably would, result in disparities in both costs and benefits and, if so, could require the preparation by the Board of a scheme for the provision of compensation as provided for in Section 131 of the Oil and Gas Conservation Act.

The Board has made some preliminary estimates of the additional recoveries which might be attainable if integrated operations were practical in the Homeglen-Rimbey, Westerose South, Westerose and Bonnie Glen D-3 Pools. It would appear to the Board that if the pressure were

fully maintained in both the Westerose and the Bonnie Glen D-3 Pools an additional some 10 million stock tank barrels of oil could be recovered by avoiding shrinkage losses. In addition, the Board believes that solvent flooding might be feasible in these two pools if a cooperative pressure maintenance scheme were established. This could provide an additional some 100 million stock tank barrels of recoverable oil. The Board recognizes that pressure maintenance would have an adverse effect on gas recoveries from the Westerose South and Homeglen-Rimbey D-3 Pools and that the loss in gas recovery could be very substantial.

The Board is now considering whether it should require the operators of the interconnected pools, or some of them, to conduct a detailed appraisal of the possible benefits and the practicability of integrated operations involving pressure maintenance and solvent flooding. The Board will discuss this matter further in a meeting with the operators involved.

The Board does not believe that the modest gas cap withdrawals proposed by Gulf, which the Board agrees will avoid inadvertent losses of otherwise recoverable oil in the Westerose D-3 Pool would significantly affect the prospects of an integrated scheme of pressure maintenance or the total recoveries possible from the pools. It does not believe that inter-pool considerations should affect the decision on the present application.

METHODS OF OBSERVATION

(1) Views of Gulf

Gulf contended that the one existing observation well, CPR Christensen #8, located in Legal Subdivision 8 of Section 33, Township 45, Range 28, West of the 4th Meridian, is adequate to monitor the oil-water interface. It stated that the well is centrally located and therefore should give fairly representative readings. Gulf estimated that the gradiomanometer measuring device permits a determination of the position of the interface to plus or minus one foot. Although, Gulf suggested that a six month measurement frequency would be adequate, it agreed that a three month frequency would have some advantages.

(2) Views of the Board

The Board believes the aquifer communication between pools in the trend is likely to cause uneven interface advancement, not detectable by a single observation point. It believes a second observation well should be established, preferably in the north half of Section 3, or the south half of Section 10.

The Board believes that a number of interface readings are necessary to determine with confidence the position or change of position of the oil-water interface. It suggests that a four month measurement frequency be established for each observation well for at least the first two years of gas cap production with the first measurements to be taken just before commencement of gas cap production. The frequency may be changed upon application after that time if it were demonstrated that fewer readings were required.

The Board will require an annual report to be filed by the operator of the Westerose D-3 Pool, summarizing the results of the interface measurements and containing the gas cap production schedule required to ensure stabilization of the oil-water interface.

DECISION

The Board approves Gulf's application to concurrently produce the oil zone and the gas cap of the Westerose D-3 Pool, subject to the following:

(1) the gas production rate from the gas cap not exceed 15 million cubic feet per day,

(2) a second well be converted thus providing two observation wells, and

(3) the oil-water interface measurements be conducted in each observation well at three approximately equally spaced times annually.

The terms and conditions of the approval are specified in Approval No. 1527 issued concurrently with this decision.

OIL AND GAS CONSERVATION BOARD

G. W. Govier
Chairman

DATED at Calgary, Alberta
May 6, 1971

OIL AND GAS CONSERVATION BOARD

Decision 71-8
Application No. 5626

GAS PROCESSING - BLACK DIAMOND
FIELD AND HARTELL AREA
SUN OIL COMPANY

THE APPLICATION AND HEARING

Sun Oil Company applied pursuant to section 38, clause (b) of The Oil and Gas Conservation Act, 1969, for approval of a scheme for the processing of gas from the Black Diamond Rundle A Pool and from the Rundle Group in the Hartell Area. The application is the first of two parts, as provided for by section 801 of the Oil and Gas Conservation Regulations, and relates to the location, the conservation levels and the pollution control features of the scheme. The plant would be located in the southwest corner of Legal Subdivision 10 of Section 12, Township 19, Range 2, West of the 5th Meridian, approximately seven miles south-east of Black Diamond and eleven miles west of High River. The capacity of the plant would be 12.3 million cubic feet per day of raw gas from which 10.8 million cubic feet of sales gas, 427 barrels of pentanes plus and 12.7 long tons of sulphur would be recovered. Sulphur not recovered would be exhausted to the atmosphere as sulphur dioxide at a maximum rate of 1.91 long tons per day through an incinerator stack 300 feet in height.

Written submissions in opposition to the application were filed by:

1. Arnold and Crawford, Barristers and Solicitors, representing a group of some fifty owners and occupiers of the area in the general neighbourhood of the location of the proposed plant,
2. Mr. L. G. Cowling,
3. Mr. A. D. Morrison,
4. the Western Stock Growers' Association, and
5. the Town of High River

The last two interventions were not received by March 19, 1971, stipulated as the deadline for receipt of submissions regarding the application in the Notice of Hearing.

The application was heard on April 13, 1971 by Board members G. W. Govier, P. Eng. and V. Millard.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Sun Oil Company	S. C. Curtin R. C. Egglestone, P.Eng. K. C. Milne, P.Eng. (of KCM Engineering Ltd.)	Sun

	Represented by	Abbreviation Used in Report
Department of the Environment	P. M. Ullman, P. Eng.	The Department
A. Hogg	A. Hogg	
L. G. Cowling	L. G. Cowling	
Board Staff	L. A. Mazurek, P. Eng. R. B. Dunbar, P. Eng.	

No one appeared at the hearing for the Western Stock Growers' Association, the Town of High River, Arnold and Crawford and Mr. A. D. Morrison to present the submissions filed by them. However, Mr. Hogg stated that he and Mr. Cowling were among those from whom Messrs. Arnold and Crawford had received instructions.

PROVISIONS OF THE ACT AND REGULATIONS

Section 1618 b of the Oil and Gas Conservation Regulations requires that the submission of each intervener be presented by a witness at the hearing. In addition section 1610 of the Oil and Gas Conservation Regulations requires that the submission of each intervener be filed with the Board by the date specified in the Notice of Hearing.

In this regard Sun stated that it had no objections if the Board wished to consider the late submissions and the submissions not represented by a witness. The Board ruled that it would receive the late submissions, and further that the submissions not presented would be made part of the record but that the Board would use discretion concerning the weight which should be given to such documents.

SUBMISSION OF THE APPLICANT

The plant would process a maximum of 12.3 million cubic feet per day of non-associated raw gas from the wells, Sun et al Black Diamond 4-13-20-2 and Sun et al Hartell 11-12-9-2. The plant facilities would provide for inlet separation, gas sweetening, dew point control, condensate stabilization and sulphur recovery. The design of the plant would permit an increase in capacity to 20 million cubic feet per day should future drilling establish the necessary reserves.

The proposed plant site would be of approximately 20 acres. The site was selected having regard to elevations, density of farm dwellings, prevailing winds, topography and accessibility. The elevation of the plant site in the vicinity of the incinerator stack is approximately 4010 feet above sea level. The surrounding land in the immediate vicinity of the site increases in elevation to the south, south-west and west and decreases in elevation in the other directions. One residence is located within a one-mile radius of the proposed site and a total of four residences are located within a two-mile radius. The prevailing winds occur from the south-west quadrants and would thus tend to carry pollutant emissions away from the surrounding higher land. The proposed site is accessible by an all weather road and can be connected to all required

utilities.

An alternate plant site, approximately two miles north and one-half mile west of the proposed site, was also considered. This location is at an elevation of 4250 feet and the surrounding land in all directions is lower in elevation. Sun stated while a shorter stack would be required there, the alternate site would offer no advantages from a pollutant dispersion standpoint. The proposed site does offer economic advantages in that it is closer to the larger of the two wells and to necessary roads and other services.

Sun stated that all of the hydrocarbons entering the plant would be conserved. Hydrocarbon vapours would be vented only during emergency situations. An emergency flare stack would be provided and would be equipped with a continuously burning pilot and a remote flame igniter. Condensate stabilizer overhead vapours would be sweetened and used as plant fuel or compressed and added to the residue gas stream. The true vapour pressure of the stored pentanes plus product would be maintained below 12 pounds per square inch absolute to minimize tank vapour losses. Hydrocarbon liquid wastes would be collected in a hold tank and conserved.

The sulphur recovery facilities would consist of a two-stage Claus type plant designed to recover not less than 93 per cent of the sulphur contained in the raw gas delivered to the plant. Sun investigated the possibility of an additional stage of conversion to further increase the sulphur recovery. It estimated that only an additional one per cent of the sulphur could be recovered with an additional capital expenditure of $50,000 to $60,000 and that the installation of such facilities would not be economically feasible.

Sun stated that it would make every effort to control pollution from the plant and would build and operate the plant in accordance with all government regulations. Unrecovered sulphur compounds would be incinerated and exhausted to the atmosphere as sulphur dioxide through a 300-foot stack. The sulphur dioxide emission rate would not exceed 1.91 long tons per day, (0.95 long tons per day of sulphur). Sun explained that the required stack height was determined using both the Sutton-Lowry and the Pasquill formulae and is sufficient to meet the 0.2 parts per million calculated maximum half-hour average concentration of sulphur dioxide at ground level which is the Department of the Environment and the Board standard in populated areas and in areas where agricultural crops are grown. The applicant contended that this maximum concentration is also well below the level which would endanger the health of plants, animals or people. The calculations also indicate that the maximum half-hour average sulphur dioxide concentrations at the four residences in the plant vicinity would not exceed 0.002, 0.014, 0.014 and 0.051 parts per million respectively and that these maximum concentrations would only occur under certain specific atmospheric and emission conditions. Offsite exposure cylinders to measure total sulphation and hydrogen sulphide concentrations on a monthly basis would be placed in accessible locations surrounding the plant site, having regard to wind direction, zone of highest pollution and influence of topography and as approved by the Board and the Department of the Environment.

Sun stated that it had considered the possibility of injecting all the acid gas to an underground formation to completely eliminate sulphur dioxide emissions. It is of the opinion that such an alternative would be very costly and would be technically difficult due to the corrosive nature of the acid gas.

All liquid hydrocarbon and treating chemical wastes would be contained in a closed drain system and would not escape to the surrounding area. Liquid obtained from surface run off and open drains would be essentially free of pollutants, and would be collected in a small holding pond and disposed of as required. All produced water removed at the plant would be separated and stored in a tank for subsurface disposal to a well in the Turner Valley Field. Sun stated that with the precautions that would be taken there would be no possibility of drainage of liquids from the plant to Tongue Creek which is near the plant site.

In reply to some of the concern expressed by the interveners, Sun stated that the plant would be equipped with automatic emergency shut down equipment to minimize emissions of sulphur dioxide and hydrocarbons if any abnormal function at the plant occurred. Sun also stated that the liquid holding pit would contain only fresh water so that in the event of a heavy rain or flash flood no pollution of Tongue Creek would occur. The applicant also presented the opinion that there would not be a tendency for sulphur dioxide to accumulate in low spots surrounding the plant and that is fact the maximum sulphur concentrations predicted by the Sutton-Lowry and the Pasquill formulae would not be exceeded.

SUBMISSION OF THE DEPARTMENT OF THE ENVIRONMENT

By letter dated April 2, 1971, the Department advised the Board that it has no objections to the application provided the Oil and Gas Conservation Regulations for air pollution control were met. The Department stated that it would establish and operate exposure cylinder stations to monitor hydrogen sulphide and total sulphation concentrations in the plant vicinity. In addition the Department, through the Board, would require that Sun operate similar stations. The Department stated that no more than four or five stations would be required.

The Department also stated that there has been no documented proof of any type of plant, animal or human deterioration at the 0.2 parts per million sulphur dioxide concentration established as the standard and is of the opinion that if the plant operated at or below this level there would not be any damage to the surrounding environment.

SUBMISSION OF MR. A. HOGG

Mr. Hogg expressed concern that

(a) abnormal conditions such as sudden flash floods or heavy thaws could cause excess run-off through the plant area which would carry pollutants from the plant to Tongue Creek,

(b) the sulphur dioxide emitted from the stack could travel over long distances and be detected several miles from the plant, and

(c) the sulphur dioxide could accumulate in low areas and reach dangerous concentrations.

Mr. Hogg stated that the weather in the area is very changeable and heavy thaws resulting in flash floods could occur. He also stated that he had detected odors from gas wells as far as fifteen miles from his residence and is of the opinion that the changeable nature of the countryside and the weather could cause the accumulation and concentration of sulphur dioxide gases.

SUBMISSION OF MR. L. G. COWLING

Mr. Cowling stated his concern about the quantity of sulphur dioxide which would be exhausted from the stack each day. He is of the opinion that the quantity should be reduced to an absolute minimum and that it should be returned to the ground, if possible.

Mr. Cowling was also concerned that the hydrogen sulphide and total sulphation cylinders would not be located where maximum hydrogen sulphide and sulphur dioxide exposures would be expected to occur.

OTHER SUBMISSIONS

The unsupported submissions of Arnold and Crawford, Mr. A. D. Morrison, the Western Stock Growers' Association, and the Town of High River will not be dealt with here. The Board has read these documents and finds no reason for varying the decision it would reach on the basis of the evidence properly before it.

FINDING OF BOARD

The Board is generally satisfied with the proposed location, conservation levels and pollution control features of the scheme. It is of the opinion that other possible plant locations exist but is generally satisfied with the proposed site, particularly in light of the proposed 300' stack and the relatively small quantity of sulphur dioxide that would be emitted. The Board is also satisfied with the proposed hydrocarbon and sulphur conservation levels, and believes that the proposed sulphur dioxide emission is minimal for this size of facility. It believes that the installation of additional recovery equipment or acid gas injection equipment is neither necessary nor practically feasible at this time. The Board is also satisfied that the waste gas and waste liquid disposal facilities have been designed to comply with all pollution regulations under its jurisdiction.

The Board appreciates the concern of Mr. Hogg, Mr. Cowling and other residents of the area but is satisfied that the facilities proposed and the regulations under which Sun would be operating are such that dangers to the environment are essentially negligible.

DECISION

The Board grants the first part of the two-part application relating to the location, the conservation levels and the pollution control features of the scheme. Processing operations are not to commence, however, until such time as the Board has approved the remaining details necessary to complete the second part of the two-part application as required by section 1404 of the Oil and Gas

Conservation Regulations. An approval for the scheme is being issued concurrently with this decision.

In addition to other normal conditions, the approval requires that the emission of sulphur compounds be limited to an equivalent of 1.91 long tons per day of sulphur dioxide at all times and that not less than 93 per cent of the sulphur contained in the raw gas delivered to the plant be recovered as elemental sulphur.

The Board reserves the right to alter the terms of the approval, if in its opinion, circumstances so warrant.

OIL AND GAS CONSERVATION BOARD

G. W. Govier
Chairman

Dated at Calgary, Alberta
May 1[illegible], 1971

OIL AND GAS CONSERVATION BOARD

Decision 71-9
Application No. 5596

Liability for unrecovered costs of the pressure maintenance scheme in Turner Valley Unit No. 3 when there is a change of ownership

THE APPLICATION AND HEARING

Western Decalta Petroleum Limited applied for direction from the Board in determining whether the liability for unrecovered costs of the pressure maintenance scheme in Turner Valley Unit No. 3 becomes the responsibility of a new owner of a tract or whether the liability for unrecovered costs up to the date of the change of ownership remains with the previous owner.

The application was heard on March 10, 1971, by the Board with Vernon Millard and N. A. Macleod, Q.C. sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Western Decalta Petroleum Limited	L. G. Elhattan R.D.V. Patel, P.Eng.	Western Decalta
Gulf Oil Canada Limited	G. A. McGuffin, P.Eng. G. A. Holland M. F. Milne	Gulf
Oakwood Petroleum Ltd.	John Stein (of McLaws & Company) D. E. Hawkins	Oakwood
Home Oil Company Limited	F. R. Erick Mulder, P.Eng. D. Repka	Home
Globe Oil Co. (1958) Ltd.	B. W. Harrison	Globe
Board Staff	D. G. Pearson, P.Eng. K. W. Fuller	

SUBMISSION OF THE APPLICANT

Western Decalta submitted that recently there have been changes in ownership in Turner Valley Unit No. 3 due to the non-payment of royalties and that similar additional changes may occur in the future. The applicant was concerned about the position of the unit operator with respect to any costs that were unrecovered at the time of change in ownership. Western Decalta therefore was seeking "the Board's assistance in determining whether the liability for unrecovered costs of the pressure maintenance scheme becomes the responsibility of a new owner of a tract or whether the liability for unrecovered costs up to the date of the change of ownership remains with the previous owner". Mr. Elhatton went on to state that the unit operator had not encountered any problems with respect to unrecovered costs arising from changes in ownership to the present time and that its concern was for the future.

VIEWS OF THE DEPUTY MINISTER OF MINES AND MINERALS

A submission by Mr. H. H. Somerville, Deputy Minister of Mines and Minerals, copies of which had been sent to the parties, was read into the record. It said, "I have your letter of February 5th regarding the above and I do not think that The Turner Valley Unit Operations Act contemplates a new owner or a previous owner. Whether or not a change in ownership occurs, the responsibility of the owner continues with ownership of the tract.".

VIEWS OF OAKWOOD

Mr. Stein, representing Oakwood, questioned whether the matter raised by the applicant was "a proper question to put to this Board". He distinguished between a request for a specific change in the Order and a general question of interpretation. Mr. Stein contended that the latter is a legal question that should be considered by the Courts.

In addition Oakwood submitted that a change of ownership in the unit does not create a debtor-creditor relationship between the unit operator and the new tract owner. Mr. Stein questioned whether such a relationship could exist at any time but in any event submitted that it could occur only between the unit operator and the tract owner at the time the expenditure was incurred.

VIEWS OF GULF

Gulf concurred with Oakwood that the application in effect puts a question of law before the Board and this may be inappropriate. It went on to state that it is nevertheless concerned about the order in that it may not clearly set forth the position of the unit operator with respect to his rights to recover capital costs, particularly where changes in tract

ownership occur. It was Gulf's view that since the normal voluntary unit agreements specifically provide that all the costs that are outstanding on the termination of the unit are paid by the various working interest owners in proportion to their interests in the unit, the same approach should be taken under the Turner Valley orders.

VIEWS OF GLOBE

Globe also agreed with Oakwood that the application was probably a question of law and should not be considered by the Board. It disagreed with the Oakwood analysis regarding the debtor-creditor relationship and contended that in acquiring an interest in a unit a party assumes responsibility for any debts associated with that interest.

VIEWS OF THE BOARD

The Board notes that the interveners, other than the Deputy Minister of Mines and Minerals but including a Turner Valley unit operator, all took the view that it is not appropriate for the Board to make general interpretations of the terms of Board Order No. TVU 3. Without commenting on this principle, the Board does not wish to make such an interpretation in the present case in view of the substantial opposition to such a course voiced at the hearing.

As the applicant stated that the problem envisaged in its application had not arisen, the Board is of the view that the remedy applied for is not needed at this time.

Western Decalta did not apply to have specific clauses in the order amended, but should it make such an application and show the need or desirability of such amendment, the Board would consider it and after a public hearing make its decision.

OIL AND GAS CONSERVATION BOARD

Vernon Millard

Vernon Millard
Board Member

DATED at Calgary, Alberta
May 11, 1971

OIL AND GAS CONSERVATION BOARD

Decision 71-10
Applications No. 5566,
5592 and 5593.

RECOVERY OF UNIT EXPENSES BY TURNER VALLEY UNITS

THE APPLICATIONS AND HEARING

In each of the subject applications, the applicant was the unit operator of the unit established by the order proposed to be amended. In Application No. 5566, Gulf Oil Canada Limited applied for amendment of clause 17, subclause (2) of Order No. TVU 5, Schedule III, clause 4 of the Order and Schedule IV of the Order. In Application No. 5592, Western Decalta Petroleum Limited applied for amendment of clause 16, subclause (2) of Order No. TVU 3, Schedule IV, clause 4 of the Order and Schedule V of the Order. In Application No. 5593, Western Decalta applied for amendment of clause 17, subclause (2) of Order No. TVU 4, and Schedule III, clause 4 of the Order.

The amendments proposed to clauses 17 of Order No. TVU 5 and Order No. TVU 4 and to clause 16 of Order No. TVU 3 each would modify the restriction on the recovery of unpaid expenses which appears in those clauses. The amendments proposed to Schedules III of Order No. TVU 5 and Order No. TVU 4 and to Schedule IV of Order No. TVU 3 would permit the rate of interest charged on unpaid acounts to vary when the bank prime rate does. The remaining amendments concern the names and addresses of Tract Agents and Working Interest Holders.

The applications were heard on March 10, 1971, by the Board, with Vernon Millard and N. A. Macleod, Q.C., sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Gulf Oil Canada Limited	E. A. McGuffin, P.Eng. G. A. Holland M. F. Milne	Gulf
Western Decalta Petroleum Limited	L. E. Elhatton R. D. V. Patel, P.Eng.	Western Decalta

	Represented by	Abbreviation Used in Report
Home Oil Company Limited	F. R. Erick Mulder, P.Eng. Don Repka	Home
Oakwood Petroleum Ltd.	John Stein (of McLaws and Co.) D. E. Hawkins	Oakwood
Board Staff	D. G. Pearson, P.Eng. K. W. Fuller, C.A.	

DEFINITION OF ISSUES INVOLVED

The common issues involved in the three proceedings, Application No. 5566, Application No. 5592 and Application No. 5593 are

(a) the rate of recovery of unpaid capital costs, and

(b) the rate of interest that may be charged by the unit operator in the event of unpaid charges.

Application 5566 and Application 5592 involved amendment of schedules to change the name and address of Tract Agents and Working Interest holders.

RATES OF RECOVERY OF UNPAID CAPITAL COSTS

(1) Views of Gulf

Gulf submitted under Application No. 5566 that the existing provision of Board Order No. TVU 5, clause 17, subclause (2) by which the Unit Operator may retain no more than 50 per cent of the net revenue allocated to a tract for the recovery of the unit tract's share of expenses for the capital costs incurred by the installation of a pressure maintenance program is too restrictive. The applicant contended that in its opinion subclause (2), should be deleted in order that an amount up to 100 per cent of net revenue could be withheld for the recovery of capital costs.

The applicant maintained that the 50 per cent restriction and the application of a fixed rate of interest of 6 per cent per annum together have created a situation whereby working interest owners are looking to the unit operator as a favourable source of funds with which to finance capital expenses incurred by the Unit and that at October 30, 1970, the unit operator had unrecovered capital costs of $23,919.44 vested in eleven working interest owners.

Mr. McGuffin, witness for the applicant, agreed that it was essential that funds sufficient to cover royalty payments would have to be available for the primary lease holder in order to protect the lease and that therefore an amount something less than 100 per cent should be retained by the unit operator.

(2) Views of Western Decalta

Western Decalta submitted under Application No. 5592 and Application No. 5593 that the provisions of Board Order No. TVU 3, clause 16, subclause (2) and of Board Order No. TVU 4, clause 17, subclause (2) should be deleted or revised so that the unit operator could recover unpaid capital costs as quickly as possible.

In addition, the applicant agreed with Gulf that the unit operator should not be placed in the involuntary position of financing capital expenses incurred by the Unit and that outstanding capital costs amounting to $174,263.61 for Turner Valley Unit No. 3 and $12,695.77 for Turner Valley Unit No. 4, existed at December 31, 1970.

Mr. Elhattan, witness for the applicant, agreed that in view of the working interest owner's responsibility to the royalty holders and because of the great variety of royalty interests in the Turner Valley area, it would be difficult to establish a rate of recovery from the unit tracts for the capital costs of the unit and that it should be somewhere between the existing 50 per cent and 100 per cent of the net revenue due the unit tracts.

(3) Views of Oakwood

Mr. Stein, representing Oakwood, contended that, as the Board initially ruled that where capital expenditure necessary to implement the pressure maintenance program was not paid by a tract owner, the operator could recover the tract's share of the expenditures out of 50 per cent of the net revenue available to the tract, it would not be proper to revise the formula on the basis of the application made by the unit operator. He also questioned whether the capital costs accumulated and unrecovered in full from the unit tracts only represent capital expenditure with respect to the pressure maintenance program or did they also include other capital costs.

(4) Views of the Board

At the time the Board considered the original applications for the formation of the Turner Valley units, there

were several proposals put forward for the recovery by the unit operator of those capital expenditures necessary to implement the pressure maintenance programs. After reviewing the transcripts, the Board is satisfied that no consideration was requested or given to a restriction of recovery for any other expenditures.

In the Board's view the Turner Valley orders permit the unit operator to recover out of tract revenues all costs allocated to the tract but in the case of capital expenditures for pressure maintenance the recovery in any month is limited to 50 per cent of the tract's net revenue. Evidence at the hearing indicated that the applicants had not taken full advantage of these provisions of the order and had restricted their recovery of non-pressure maintenance capital expenditures to the same 50 per cent limitation.

The Board does not believe that it would be possible to determine a common percentage of net revenue that was something less than 100 per cent and greater than 50 per cent, nor does it believe that the restriction on recovery rate should be removed. With the accelerated recovery available to the operator for 'other' capital expenditure, together with an increased rate of interest charged, the Board does not feel that the operator is in an unreasonable position for the recovery of the outstanding capital expenditures.

RATE OF INTEREST THAT MAY BE CHARGED
BY THE UNIT OPERATOR

(1) Views of Gulf

Gulf submitted under Application No. 5566 that the existing provision of Board Order No. TVU 5 Schedule III, clause 4 which provides for a charge for interest at the rate of 6 per cent per annum on unpaid charges against the working interest owners has assisted in placing the unit operator in the position of an unwilling banker. The applicant was concerned that the situation whereby certain working interest owners are looking to the unit operator as a favourable source of funds with which to finance capital expenses incurred by the unit, was reaching the point where established companies with means are availing themselves of this advantage. The applicant proposed that the reference to "rate of 6 per cent per annum" in Schedule III clause 4 be deleted and replaced by the words "rate one per cent greater than the prime bank rate of the principal chartered bank in Canada used by the unit operator.".

(2) Views of Western Decalta

Western Decalta submitted under Application No. 5592 and Application No. 5593 that the provisions for a charge for interest at the rate of 6 per cent per annum on unpaid charges against the working interest owners in Schedule III, clause 4 of

Board Order TVU 4 and in Schedule IV, clause 4 of Board Order TVU 3, should be replaced by a provision that would allow interest charges at a rate of one per cent greater than the prime bank rate of the principal chartered Bank in Canada used by the Operator.

(3) Views of Oakwood

Mr. Stein, representing Oakwood, submitted that the unit operator should not be penalized and that the request for a surcharge of one per cent in addition to the prime bank rate was reasonable.

(4) Views of the Board

The Board agrees with the views of the applicants that the fixed rate of interest allowed presents an unnecessary hardship on the unit operators and that this could be corrected by providing a floating rate that would be a percentage higher by one than the subsisting prime bank interest rate.

CHANGE OF NAME AND ADDRESS OF CERTAIN TRACT OWNERSHIPS

(1) Views of Gulf

Gulf submitted under Application No. 5566, that Schedule IV of Board Order TVU 5 should be amended as to Tracts 207 and 220 so that the Tract Agent for each tract be changed from Mr. C. Innes, 540 - 17 Avenue N. W., Calgary 43, Alberta, to Mill City Petroleums Limited, 210 Fina Building, 736 - 8 Avenue S. W., Calgary 2, Alberta.

(2) Views of Western Decalta

Western Decalta submitted under Application No. 5592 that Schedule V of Board Order TVU 3 should be amended as to Tract 16 by striking out the name and address of the Tract Agent of Owner and the Working Interest Holder therein and substituting the name of "Oakwood Petroleum Limited".

(3) Views of the Board

The Board is of the opinion that these parts of the application are of a routine nature and should be granted.

DECISION

With respect to Application No. 5566, the Board grants the application for amendment of Schedule III and IV of Order No. TVU 5. It denies the application with respect to clause 17.

With respect to Application No. 5592, the Board grants the application for amendment of Schedules IV and V of Order No. TVU 3, and denies the application with respect to clause 16.

With respect to Application No. 5593, the Board grants the part of the application relating to Schedule III of Order No. TVU 4, and denies that with respect to clause 17.

The amending orders will be circulated in the usual manner after registration.

OIL AND GAS CONSERVATION BOARD

Vernon Millard
Board Member

DATED at Calgary, Alberta
May 21, 1971.

ENERGY RESOURCES CONSERVATION BOARD

Decision 71 - 11
Application No. 5594

Application for Concurrent Production
and Good Production Practice
Judy Creek Viking A Pool

THE APPLICATION AND HEARING

Imperial Oil Limited applied, with respect to the Judy Creek Viking A Pool, for

(a) concurrent production of oil and gas-cap gas, and
(b) permission to produce the oil accumulation in accordance with good production practice at a maximum oil rate of 6100 stock tank barrels (STB) per month times the gas-oil ratio penalty factor determined using Table 2500 of Schedule 6, Part A, of the Oil and Gas Conservation Regulations.

The application was heard on March 11, 1971, by the Board, with Mr. A. F. Manyluk, P. Eng. and Mr. V. Millard sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Imperial Oil Limited	W. B. Baker, P. Eng. G. A. Reitzel H. S. Simpson, P. Eng.	Imperial
	P. E. denHartog (D & S Petroleum Consultants Ltd.)	D & S
	R. A. Rudkin, P. Geol. (R. A. Rudkin Consultants Ltd.)	
Great Plains Development Company of Canada, Ltd.	T. W. Adamson, P. Eng. L. Ruus	Great Plains
	P. E. denHartog (D & S Petroleum Consultants Ltd.) R. A. Rudkin, P. Geol. (R. A. Rudkin Consultants Ltd.)	
Kerr-McGee Corporation	B. O. Holliday	Kerr-McGee
Oil and Gas Conservation Board	C. C. Fortems, P. Eng. H. C. Moster F. Phillips, P. Geol.	Board Staff

BACKGROUND AND SUBMISSIONS

The Judy Creek Viking A Pool (herein called the "Viking A Pool") was discovered during the development of the Judy Creek Beaverhill Lake A Pool. Gas production from the Viking A Pool commenced in December, 1963 providing a source of fuel gas for the various facilities of the Judy Creek complex. An oil accumulation was discovered in the western portion of the Viking A Pool in September, 1969, and put on production in that same month.

In addition to serving as a source of fuel gas, Imperial has been using the Viking A Pool for storage of excess gas from the Judy Creek Beaverhill Lake A Pool and the Judy Creek Beaverhill Lake B Pool, having been granted permission to do so by the Oil and Gas Conservation Board in Approval No. 907 issued in October, 1966. This approval was later re-issued as Approval No. 1230 and again amended in December, 1970.

In August, 1967, the Board issued Approval No. 975 to Imperial of a scheme for the processing of gas produced from the Viking A Pool at a plant with a capacity of 26 million cubic feet per day.

In October, 1968, Approval No. 1104 was issued to Great Plains approving a scheme for processing a maximum of 1.95 million cubic feet per day of Viking A Pool gas. This approval was subsequently amended in December, 1970 increasing the maximum to 5.0 million cubic feet per day.

The Oil and Gas Conservation Act since January 1, 1968, requires the approval of the Board for the concurrent production of an oil accumulation and its associated gas cap. With discovery of oil in September, 1969 and a subsequent ruling by the Board that the oil accumulation was in communication with the updip gas, the matter of concurrent depletion was raised with the operators. To afford the operators adequate time to study this matter, the Board issued Approval No. 1313 permitting a temporary continuance of concurrent depletion in the Viking A Pool until December 31, 1970. Subsequent amendments extended the approval to May 31, 1971.

At present there are three oil wells and seven gas wells producing from the pool. The Board's current estimates of the initial gas and oil in place are 85 billion cubic feet and 7.21 million barrels, respectively. Recoverable reserves are estimated to be 65 billion cubic feet of marketable gas and 1.08 million stock tank barrels of oil.

Technical studies relating to and submitted in support of the subject application are

(a) "Reservoir Depletion Study, Judy Creek Viking A Pool - October 1970" prepared by D & S Petroleum Consultants Ltd. (hereinafter called the "D & S Study"), and

(b) "Optimum Depletion Study, Judy Creek Viking A Pool - January 1971", prepared by Imperial (hereinafter called the "Imperial Study").

The D & S Study was prepared for Imperial and Great Plains to determine the probable fluid distribution in the Viking A Pool and the most suitable method

whereby these fluids could be produced. The study included an investigation of primary oil production with deferred gas cap withdrawals, water flooding of the oil accumulation, concurrent production of the oil accumulation and its associated gas cap, and concurrent production with good production practice.

The Imperial Study included Imperial's present interpretation of the fluid distribution in the reservoir and the effect on recovery of primary oil production with no gas cap withdrawals, concurrent production and concurrent production with good production practice at a restricted oil production rate.

Great Plains intervened in support of the application but proposed a much higher oil production rate. In addition, its intervention raised a question pertaining to alleged inequitable withdrawals from the gas cap. At the hearing the Board ruled that this latter matter did not lie within the terms of reference of the hearing and therefore was not admissible.

Kerr-McGee intervened solely for the purpose of cross-examination.

DEFINITION OF ISSUES

Production of a gas cap concurrently with production of the communicating oil accumulation would normally result in a lesser recovery of oil than if production from the gas cap were deferred until the oil accumulation were depleted. The concern of the Board in this application was whether or not the concurrent production of the oil and gas cap now under way should be continued and if so under what conditions.

The issues in the application are therefore

(a) the quantities and relative distribution of oil and gas in the reservoir,
(b) the magnitude and economic significance of the losses of recoverable oil under continued concurrent production with oil production at prorated rates,
(c) possible measures to reduce or eliminate such losses,
(d) correlative rights of owners within the gas cap, and
(e) solution gas gathering

QUANTITIES AND DISTRIBUTION OF RESERVOIR FLUIDS

(1) Views of Imperial

The D & S Study concluded that

1. The oil in the Viking A Pool was known to exist only in the western portion of the reservoir but may be postulated to extend along the downdip edge of the pool into the eastern regions.

2. The gas in place in the Viking A Pool amounted to some 82.2 billion cubic feet (Bcf) if the oil leg underlaid the entire gas pool and some 93.2 billion cubic feet (Bcf) if the oil leg was confined to the western portion.

3. The possible oil in place for the entire oil leg was estimated to be 28.2 million stock tank barrels with 9.05 million stock tank barrels in the western region.

Furthermore, the D & S Study recommended that the well bores of five Judy Creek Beaverhill Lake wells be utilized to test the postulated Viking A Pool oil leg in the eastern portion of the reservoir.

Imperial, in the Imperial Study, confined its estimate of initial oil in place to the "proven" area, in the western portion of the pool, in the vicinity of the three producing oil wells. A "proven" area of 800 acres and an initial oil in place of 2.43 million stock tank barrels was calculated.

Imperial, indicated that its interpretation of volume of oil in the eastern portion of the pool was extremely small and any loss to the gas cap would probably be insignificant.

Imperial also stated that all Beaverhill Lake wells located in the postulated eastern oil leg were either under production or capable of production. As it had reservations about the adequacy of the cementing of the production casing opposite the Viking pool, any attempt to test the Viking would be extremely risky, especially if the well should be needed for Beaverhill Lake production. The only existing Beaverhill Lake well suitable for a Viking test was the well in Legal Subdivision 12 of Section 34, Township 63, Range 11, West of the 5th Meridian as it has experienced excessive Beaverhill Lake water production. However, it would be one of the last wells to be selected due to its poor location with respect to the postulated Viking oil leg.

Imperial's estimate of initial gas reserves was stated to be volumetrically defined by good well control and confirmed by extrapolation of a P/Z versus cumulative production plot. Its estimate yielded an initial gas in place of 82.2 billion cubic feet.

(2) Views of Great Plains

Great Plains did not make any representation regarding the question of whether an oil leg was present along the complete downdip edge of the Viking reservoir.

It stated that it did not agree with Imperial's arbitrary reduction of the D & S estimate of oil in place in the western portion of 9.05 million stock tank barrels to 2.43 million stock tank barrels. Great Plains believed that the best estimate of oil in place was the D & S estimate of 9.05 million stock tank barrels.

(3) Views of Kerr-McGee

Kerr-McGee did not disagree with the estimates of oil and gas in place as stated in Imperial's application. However, since it professed intentions of additional development drilling in the western portion, it stated that should this subsequent drilling substantiate the presence of significantly larger oil in place, the Board should review and re-evaluate the entire situation making adjustments deemed necessary.

(4) Views of the Board

Prior to the hearing, the Board's estimate of oil in place for the western portion of the pool was 7.21 million stock tank barrels. A more recent evaluation by the Board staff assigned to this portion of the reservoir an initial

proven oil in place of 3.16 million stock tank barrels and a proven plus probable value of 8.2 million stock tank barrels. The Board has adopted these volumes.

The Board believes there is a reasonable chance that significant oil does exist in the eastern portion of the pool and of the amount estimated in the D & S Study. In view of the magnitude of the reserve it is in the Board's opinion important to resolve this uncertainty since under concurrent depletion much, if not all, of the oil if present would be lost unless specific steps were taken to develop and produce it. The resulting waste would be intolerable.

The Board considers it essential that prolonged production of the gas cap not be permitted until the extent of the oil accumulation has been satisfactorily evaluated. The Board believes a satisfactory solution could be the adoption of the D & S Study recommendation that a group of Judy Creek Beaverhill Lake wells be tested to confirm or deny the existence of an oil leg in the eastern portion of the Viking A Pool. It appreciates that there are certain risks associated with using a Judy Creek Beaverhill Lake well for test purposes but believes that the potential conservation gain is sufficiently great to justify the risk. Alternatively a series of test holes would provide the desired information.

The Board's present estimate of gas in place is 85 billion cubic feet which is in close agreement with the estimate by D & S and Imperial.

LOSSES OF RECOVERABLE OIL

(1) Views of Imperial

The D & S Study estimates maximum recoverable reserves at 6.06 million stock tank barrels (21.5 per cent of oil in place) under primary depletion of the oil accumulation with no production from the gas cap. This estimate assumes a residual oil saturation of 30 per cent and an oil leg extending along the entire downdip edge of the reservoir. D & S calculated that, if the existing concurrent depletion were continued with oil production at prorated rates, ultimate reserves would be 1.36 million stock tank barrels (4.85 per cent of oil in place) and a loss of recoverable oil attributed to concurrent depletion of 4.70 million stock tank barrels.

Imperial contended that, using the estimate in the Imperial Study and on the basis of its proved oil in place of 2.43 million stock tank barrels, the recoverable oil would amount to 0.194 million stock tank barrels (8 per cent of oil in place) if concurrent production were continued at prorated oil rates and a gas rate of 3.65 Bcf per year. This recovery would be increased to approximately 0.522 million stock tank barrels (21.5 per cent of oil in place) if the gas cap were shut in and the oil were produced at prorated rates.

(2) Views of the Board

The Board has evaluated recoverable reserves by using a one-dimensional reservoir simulator and assuming oil to exist in only the western portion of the reservoir. This approach resulted in approximate confirmation of the recovery factors suggested by the Imperial Study. For the case of prorated oil production with gas cap production a recovery factor of 8 per cent was calculated, whereas for the case of prorated oil production without gas cap production a recovery factor of 20.4 per cent was calculated.

In the light of the potential of recoverable oil in the easter regions of the pool, the Board considers it necessary to consider the potential losses in this area. The following table summarizes the Board views regarding the recoverable reserves according to regions and the type of depletion. Since the Board, pending tests, accepts D & S's oil in place for the eastern region, the recoverable reserves shown in the table pertaining to that region have been calculated on the basis of the D & S oil in place and the Board's recovery factors.

		Western Region		Eastern Region
		Proved	Proved & Possible	Possible
		(Thousands of Stock Tank Barrels)		
1.	Oil in place	3160	8200	19100
2.	Recoverable reserves (prorated oil production-no gas cap production)	645	1670	3896
3.	Recoverable reserves (prorated oil production with gas cap production)	253	656	1530
4.	Losses of Recoverable Oil (2-3)	392	1024	2366

The Board adopts the above values for the purpose of considering this application.

MEASURES TO REDUCE OIL LOSS

(1) View of Imperial

D & S in its study considered downdip and updip water injection as well as concurrent depletion with good production practice (GPP) as possible methods for minimizing oil losses. Downdip water injection was discarded because of the wide spacing pattern dictated by the shape of the oil accumulation and the risk of driving oil into the gas cap. In the analysis of updip water injection, injection wells were strategically placed along the zero oil isopach and piston-like displacement was assumed as was a 30 per cent residual oil saturation. Utilizing these assumptions, a recovery of 7.147 million stock tank barrels (25.4 per cent of oil in place) was predicted, which D & S felt was optimistic. However, the extremely high capital and operating costs of such a scheme and the considerable risk associated with it, made it less attractive than concurrent depletion with GPP.

Under continued concurrent depletion but with GPP, D & S assumed no gas cap expansion drive and predicted a recovery of 2.9 million stock tank barrels (10.3 per cent of oil in place). From its studies D & S concluded that optimum oil recovery would be obtained under GPP with the oil production rate sufficent to cause uniform pressure depletion of both the oil and gas accumulations.

Imperial in its study, contended that enhanced recovery by updip water injection, which was rejected for economic reasons in the D & S Study, was also not feasible in the western portion of the pool. It did not consider other forms of enhanced recovery. Imperial also contended that the shutting in of gas

production adjacent to the gas-oil interface would have little effect in preventing migration due to the good transmissibility of the reservoir as indicated by pressures.

Imperial stated that the best possible means to reduce oil loss due to migration into the gas cap under concurrent depletion, was to accelerate the oil production rate through permitting GPP. A maximum rate of 6100 stock tank barrels per month was recommended to create and continue a lower pressure in the oil accumulation than in the gas cap. Furthermore, Imperial suggested that at the proposed oil and gas production rates, an ultimate recovery of 0.510 million stock tank barrels (21 per cent of oil in place) could be realized.

(2) Views of Great Plains

Great Plains agreed that to reduce oil losses to the gas cap through migration, an equivalent gas cap and oil accumulation pressure must be maintained. Based on its adopted oil in place of 9.05 million stock tank barrels, the recommended maximum oil production rate under GPP was 14,500 stock tank barrels per month, with the net gas production from the gas cap restricted to the 3.65 billion cubic feet per year proposed by Imperial.

(3) Views of Kerr-McGee

Kerr-McGee stated it was in support of the Imperial's application. However, it would agree to a somewhat larger oil rate to curb oil migration, as it believed the oil in place to be larger than that suggested by Imperial.

(4) Views of the Board

The Board recognizes that one method of eliminating the loss in oil recovery is to deny concurrent production. In view of the chronological sequence in the development of the Viking A Pool, the Board does not believe that this would be a reasonable solution. Accepting the principle of concurrent production the Board, based on information available for the western region, has considered the possibility of restricting gas production in the vicinity of the gas-oil interface, and water injection at the gas-oil interface, as methods of reducing oil losses. The Board agrees that the excellent communication makes the former not feasible while the latter does not appear to be a practical proposal due to the uncertainties regarding the configuration of the oil leg, the very large volumes of water required to achieve effective separation of the oil and gas and the probability of early water breakthrough. Accordingly, the Board thinks that the most reasonable scheme to minimize oil losses would be to increase oil production rates so as to create a lower pressure in the oil accumulation than in the gas cap. The oil rate required to create this pressure differential would depend upon the oil in place. Any new development or reassessment of reserves would require a review of the oil production rate.

Based upon the Board's proved oil in place of 3.16 million stock tank barrels and a net gas cap gas production rate of 3.65 billion cubic feet per year, the Board estimates that an oil rate of 9150 stock tank barrels per month would increase oil recovery to 0.613 million stock tank barrels, which appears to the Board to be the best recovery obtainable in the circumstance. For reasons of administrative simplicity, the Board would assign such a rate of depletion on a per well basis which would provide a GPP rate of 100 barrels per day per well. The Board considers such a rate will have a minimal impact on the proration plan, having regard to the conservation gain and probable extent of the oil reserve.

CORRELATIVE RIGHTS OF OWNERS WITHIN THE POOL

(1) Views of Imperial

Imperial stated that the net gas cap gas production should be restricted to 3.65 billion cubic feet per year. Furthermore, Imperial proposed that a penalty factor from Table 2500 of Schedule 6, Part A, of the Oil and Gas Conservation Regulations be applied to the oil production rate limitation to protect the gas cap owners should early gas cap breakthrough occur in the oil accumulation.

(2) Views of Great Plains

Great Plains agreed that the gas-oil ratio penalty schedule proposed by Imperial would protect the interests of the gas cap owners.

(3) Views of the Board

The Board agrees with the restriction of the gas cap gas production to 3.65 Bcf per year and with the use of 2500 GOR table proposed by Imperial.

SOLUTION GAS GATHERING

(1) Views of Imperial

Imperial stated that it had not studied such a scheme other than that mentioned in the "Reservoir Depletion Study" and that such a study was up to the oil producers.

It agreed that approximately one-half billion cubic feet of solution gas could be produced over the life of the pool at a sales value of about $85,000.00.

(2) Views of Kerr-McGee

Kerr-McGee stated that at present its well was producing at a GOR of about 375 cubic feet per barrel, and therefore gas gathering was not economic at present. Should the application be approved and GOR's increase or additional development substantiate increase reserves, then if it were economic to do so, gas gathering should be initiated.

(3) Views of the Board

Normally, the Board has required gas gathering as an integral condition of a concurrent depletion approval. In this case, however, the quantity of solution gas associated with the now proved oil reserves does not appear to warrant gas gathering, but should this situation change the possibilities of gathering solution gas would be reviewed.

DECISION

The Board will grant Imperial's application for approval of a scheme for the concurrent production of the oil accumulation and it associated gas cap in the Judy Creek Viking A Pool, subject to the following:

1. Oil may be produced on a good production practice basis subject to a limitation of 100 barrels per day per well times the gas-oil ratio penalty factor determined using Table 2500 of Schedule 6, Part A, of the Oil and Gas Conservation Regulations.

2. The net gas production rate from the gas cap shall not exceed 3.65 billion cubic feet per calendar year.

3. Imperial shall before October 1, 1971, test appropriate existing wells or drill and test selected test wells to the Viking A Pool as approved by the Board, to determine whether or not a Viking oil leg is present in the eastern portion of the pool.

4. Performance of the reservoir shall be reviewed and appraised annually by the owners and reported to the Board.

5. The terms and conditions of the approval are specified in Approval No. 1537 issued concurrently with this decision and the Board reserves the right to alter the terms of the approval, if in its opinion, circumstances so warrant.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Vice Chairman

DATED at Calgary, Alberta
June 3, 1971

ENERGY RESOURCES CONSERVATION BOARD

Decision 71-12
Application No. 5396

CONCURRENT PRODUCTION OF OIL ZONE AND GAS CAP WITH GAS CAP CYCLING AND PARTIAL WATER FLOODING OF OIL ZONE - HARMATTAN-ELKTON RUNDLE C POOL

THE APPLICATION AND HEARING

Canadian Superior Oil Ltd., on behalf of the working interest owners in the Harmattan-Elkton Unit No. 1 applied, pursuant to section 38 of The Oil and Gas Conservation Act, for approval of a scheme to produce concurrently the oil accumulation and its associated gas cap in the Harmattan-Elkton Rundle C Pool. Specifically, it applied for approval of a scheme for

(a) pressure maintenance by water injection in a northern segment of the oil zone,

(b) production of the oil zone in accordance with good production practice with a pool maximum rate limitation of 6,000 barrels of crude oil per day as of January 1, 1972,

(c) commencement of gas sales in January 1972, from the south-east segment of the gas cap at a gas sales rate of 50 million cubic feet per day,

(d) termination of gas cap cycling and increasing the gas sales from the gas cap to the full contract rate(1) commencing January 1, 1977, and

(e) advancement of the existing gas cap cycling operation toward the oil zone.

The application was heard on February 23, 1971, by the Oil and Gas Conservation Board with G. W. Govier, P. Eng., A. F. Manyluk, P. Eng. and Vernon Millard sitting.

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(1) The contract rate was not specifically set out in the application, but 134 million cubic feet per day was used in the technical studies and the Board assumed this rate to be the contract rate.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Canadian Superior Oil Ltd.	L. R. Miskew, P. Eng. M. T. Alexandre, P. Eng. L. L. Crain R. C. MacDonald	Canadian Superior
Board Staff	D. R. Craig, P. Eng. J. A. Bray, P. Eng. N. G. Berndtsson, P. Eng.	

BACKGROUND

The Harmattan-Elkton Rundle C Pool is unitized under the Harmattan-Elkton Unit No. 1 which provides for different participation for the oil zone and the gas cap owners. The gas cap of the pool is currently being cycled at a rate of approximately 30 billion cubic feet per year to recover natural gas liquids from it. Board Approval No. 967 authorizes the cycling scheme. To date, the cumulative average recovery of condensate is approximately 44 barrels per million cubic feet of gas cycled. Reservoir voidage created by the cycling scheme is replaced by make-up gas from the Harmattan-Elkton Rundle B Pool. The solution gas from the Harmattan-Elkton Rundle C Pool oil production is conserved and injected to the gas cap. The oil zone is subject to proration.

The Harmattan-Elkton Rundle C Pool is a dolomitic monoclinal stratigraphic trap dipping westward at approximately one degree. The updip limit of the reservoir is defined by an erosional edge and by porosity and permeability pinch-outs. There is a finite aquifer downdip of the hydrocarbon accumulation. The average original gas-oil and oil-water contacts were at 5360 and 5442 feet subsea, respectively. The initial reservoir pressure was 3630 pounds per square inch gauge (psig) at 5360 feet subsea. By July 1970, the average reservoir pressure had declined to 3335 psig at 5360 feet subsea. As of December 31, 1970, the Board estimated the pool's initial gas and initial oil in place to be some 1,150 billion cubic feet and 188 million stock tank barrels, respectively. Sixteen million barrels of natural gas liquids and 24.8 million stock tank barrels of crude oil have been produced from the pool as of December 31, 1970. No gas has been sold from the pool.

TECHNICAL STUDIES

In assessing the effects on reservoir recoveries of various operational programs, Canadian Superior utilized both two dimensional (2-D) and three dimensional (3-D) model studies of the pool. Six cases from each of the 3-D and 2-D results were presented. The former are referred to as Cases I to VI while the latter are called slice Cases S-1 to S-6. A Case VII was developed at the Board's request based on information from Case I and Cases S-1 and S-3. Also, as requested by the Board at the hearing, Cases VIA and VIB were provided. Case VI is essentially the scheme which the applicant is requesting the Board to approve. Canadian Superior's summary of the results of Cases I to VII are attached to this report as Table 1.

Canadian Superior pointed out that it is not valid to compare results from the 3-D cases directly with 2-D slice cases but it is proper to compare the 3-D cases with one another and the slice cases with one another to evaluate the effects of changing conditions. The applicant expressed considerable confidence in the validity of such comparisons but indicated that its confidence in the absolute value of any estimated recovery was notably less.

The Board appreciates the complexity and the extent of the technical studies carried out by the applicant. Unfortunately, the reservoir model developed by Canadian Superior is not capable of realistically simulating water and gas coning which are important phenomena in considering the effectiveness of oil recovery operations. The Board is also concerned with the accuracy of simulating the reservoir hydrocarbons by a three-component system. In addition, because of the approach taken by the applicant, it is difficult to isolate in the various cases the effect of specific changes in the operational program. Notwithstanding the deficiencies of the studies, the Board accepts that the results are meaningful for comparative purposes.

DEFINITION OF TERMS

The applicant studied a variety of operational programs having different schedules for depletion of the gas cap and different conditions for depletion of the oil zone. For convenience, the Board has identified the various programs by a code. This code is illustrated by the example "30-77-100:6000 GPP-WFN". In this code, the first number refers to the gas sales rate in millions of cubic feet per day (MMCFD) while cycling of the gas cap continues. The second number refers

to the date when cycling stops and gas sales commence at a rate in MMCFD indicated by the third number. The fourth number is the pool oil production maximum rate limitation in barrels of oil per day (BOPD). The symbols following indicate good production practice and water flooding of the northern segment of the pool. The absence of "GPP" in the code expression means the oil zone is prorated and the absence of "WF" means the oil is produced under primary depletion. The Board code for Cases I to VII has been included in Table 1.

The term "liquid or liquids" as used in this report in discussing recovery of hydrocarbons from the pool includes crude oil, condensate, propane and butanes.

The applicant used the terms "partial sales" which refers to the sales rate indicated in the first number of the Board code and "blowdown date" which refers to the second number of the code, i.e. the year of termination of cycling and commencement of full scale gas sales.

DEFINITION OF ISSUES INVOLVED

The Board believes that the application requires the consideration of the following matters:

(a) the desirability of water flooding the oil zone,

(b) the effect of crude oil production rate on crude oil recovery,

(c) the impact of increased oil production rates on the proration plan,

(d) modifications to the gas cap cycling scheme,

(e) the effect of the gas schedule on hydrocarbon recoveries,

(f) economic considerations and conservation, and

(g) the area from which sales gas should be produced.

The oil in place and gas in place are not reviewed at this time.

THE DESIRABILITY OF WATER FLOODING THE OIL ZONE

(1) Views of the Applicant

Canadian Superior contended, on the basis of both the current studies and the feasibility studies submitted to the Board in 1962, that water flood operations for the entire oil zone are not justified.

The applicant submitted that injecting water at the gas-oil contact would be ineffective since much of the water would invade the gas saturated formation at the injection well bores and thus would not ensure effective displacement of the oil zone. On the other hand, the applicant contended that if the injection wells were located further downdip of the gas-oil contact a significant volume of the oil zone would not be contacted by injected water updip of the injectors. These conclusions were, according to the applicant, substantiated by the 2-D model studies which showed that at an oil production rate of 4,000 barrels per day no increase in the pool oil recovery would be obtained by injecting water at the gas-oil contact. A modest increase of 2 million barrels was shown in condensate recovery due to the pressure maintenance provided by the injected water. Similar results were obtained for a 6,000 barrel per day oil production rate which showed an increase of some 3 million barrels in each of the condensate and oil recoveries, again a modest increase considering that the cumulative water injected was some 185 million barrels.

Studies presented in 1962 concluded that injection of water to the aquifer and at extreme downdip points in the oil zone would not provide any significant increase in oil recovery. The volumetric sweep of the oil zone was poor because a large portion of the downdip west side of the pool would not be swept by injected water. The applicant stressed the risk of gas and water coning contributing to poor sweep efficiencies.

In addition to considering water flood operations for the entire pool, the applicant also assessed water flooding only the northern segment. Primary depletion predictions made by the applicant using the 3-D model showed that the residual oil saturation in the northern segment was significantly higher than in the remainder of the pool. This was attributed to the relatively small area of the gas cap overlying the oil column in the northern segment. The model studies predicted appreciably increased oil recovery by injecting water downdip in the aquifer or oil column of the northern segment. The applicant considered coning losses

to be less severe in the northern part of the pool, thereby reducing the risk associated with water flood operations.

In view of these studies, Canadian Superior proposed to increase the oil recovery of the Harmattan-Elkton Rundle C Pool by water flooding the oil zone area north of the south boundaries of Sections 17 and 18 of Township 32, Range 4, West of the 5th Meridian. This area is referred to as the northern segment in this report. The applicant estimated that an additional 9 million barrels of oil would be recovered over the estimated 14 million barrels of primary oil recovery. The applicant's reservoir parameters are shown in Table 2.

Canadian Superior stated that if the proposed water flood scheme, which involves more than one-third of the pool's oil in place, performs satisfactorily consideration would be given to expanding it to cover more of the pool.

(2) Views of the Board

The Board has reviewed its May 1965 conclusions regarding the feasibility of improving oil recovery by water flooding the entire oil zone in the Harmattan-Elkton Rundle C Pool. Studies preceding these conclusions made by the Board and studies presented in 1962 by Canadian Superior indicated that the benefits of water flooding either downdip in the aquifer or on a pattern basis were marginal, particularly having regard for the risks involved, including water and gas coning.

In order to provide more information on coning tendencies and the risks they may present with respect to water flooding, the Board has investigated the performance of the oil wells in the pool. Both the cumulative and the current water-oil ratios of the wells were considered having regard for the completion interval with respect to the oil-water interface and to the location of the well in the pool. Definite evidence of water coning was found and 50 per cent of the wells in the area of the pool with bottom water present have produced significant quantities of water. It was found that 23 per cent of the wells in the northern segment, compared to 75 per cent of the wells in the remainder of the pool with bottom water, have produced significant quantities of water. However, based on data to the end of 1969, only four wells had water-oil ratios in excess of one, indicating that although water coning is quite prevalent, the situation is not particularly serious.

While the emphasis of the Board performance study was on water coning, it was noted that appreciable excess gas is produced by many oil wells. This is mostly attributed to gas

coning because the oil wells producing with significant gas-oil ratios are located in the area having a gas-oil contact.

The Board agrees with the applicant that injection of water at or near the gas-oil contact would not improve recoveries because of poor volumetric sweep of the oil zone. However, in the Board's opinion, reservoir studies and studies of oil well performance do not completely eliminate the possibility of water flooding the entire pool by injecting water into the aquifer or downdip in the oil zone. Having regard for the potential risks associated with coning, the Board is prepared at this time to accept the results of the applicant's studies that only limited improvement in oil recovery would be achieved by water flooding the entire pool and that pool-wide water flooding should not be initiated at present.

The Board studies confirmed those of the applicant that in the northern segment an appreciable increase in oil recovery could be obtained by injection of water. As the applicant contended and as previously noted, coning tendencies were found to be less serious in the northern segment as compared to the remainder of the pool. Therefore, water flooding is more likely to be successful and the Board believes it should proceed as soon as possible. The Board believes that if the proposed flood proves successful and it appears that water coning is not made more serious by the injection of water, consideration should be given to expanding the scheme to other areas of the oil zone.

In estimating the increase in oil recovery attributable to water flooding the northern area, the Board noted that the applicant did not present detailed information on the residual oil saturations. It is therefore not possible to make detailed comparison of the applicant's recovery estimates with the Board's estimates of sweep efficiencies and of residual oil saturations from laboratory flood tests. Consequently, only the final recovery figures can be directly compared. The comparison is shown in Table 2. The Board estimates that water flooding the north segment would increase the oil recovery by 6 to 7 million barrels.

THE EFFECT OF CRUDE OIL PRODUCTION RATE ON CRUDE OIL RECOVERY

(1) Views of the Applicant

The applicant contended that crude oil recovery could be significantly increased by accelerating oil production rates while the reservoir pressure is at a relatively high level.

This was demonstrated with results from a 2-D slice model which indicated increased oil recovery with increasing oil production rates. At the hearing, Canadian Superior provided an estimated oil recovery-oil rate relationship for Case VI conditions which was based on the slice model results. The estimates were 51.5, 54.6 and 56.0 million barrels recoverable oil for maximum production rates of 4,000, 6,000 and 8,000 barrels per day respectively. The increase in oil recovery becomes progressively less as the oil production rate increases; the progression ranges from 2.0 to 0.6 million barrels recovery per thousand barrels per day rate increase over the 4,000 to 8,000 barrels per day oil production range. The increased recovery occurs primarily in the southern two-thirds of the pool because the productive capacity of the northern area proposed for water flooding is limited. Canadian Superior's analysis for Case VI shows that the pool oil productivity drops below 6,000 barrels per day in 1976. However, by taking advantage of available oil productivity prior to this date, oil recovery can be improved before the reservoir pressure declines as a result of gas cap production.

The applicant also submitted that the increased oil production rate provides the benefit of minimizing hardships on gas cap owners by advancing the date at which gas cap blowdown can commence.

(2) Views of the Board

The Board notes that the applicant did not allow for water coning in its presentation on the effects of oil production rate. Bearing in mind the coning tendencies of the wells, the Board is concerned that increased rates may have some adverse effects on recovery. From the Board's coning investigation it appears that the present surplus non-producing oil wells cannot be expected to add much to the pool's productivity. Therefore, most of the increase over current allowable rates must come from active wells. The applicant indicated the northern segment would not contribute additional productivity. The remainder of the pool has the greater apparent tendency to cone water. As previously stated, water-oil ratios are not extreme at this time. Some of the better wells producing at rates of 150 to 200 barrels per day have reasonably stable water-oil ratios ranging from 0.2 to 1.2. At this time, the Board does not consider that a rate limitation on each individual well is necessary, but if good production practice is approved, production rates and well performance must be kept under surveillance.

With some reservation because of possible coning problems, the Board concurs with the applicant that increased rates of oil production will improve oil recovery in the Harmattan-Elkton Rundle C Pool under concurrent production operations. The degree to which the production rate should be increased over normal prorated rates depends upon the recovery gain and the impact on the proration plan. The Board accepts Canadian Superior's estimate of improved recovery with increased rate of production and accepts an incremental gain in recovery of 0.8 million barrels for an increase in the maximum oil production rate from 6,000 to 7,000 barrels per day and a gain of 0.6 million barrels for an increase in the maximum production rate from 7,000 to 8,000 barrels per day. The assessment of these recoveries in relation to the impact on the proration plan is discussed later.

THE IMPACT OF INCREASED OIL PRODUCTION RATE ON THE PRORATION PLAN

(1) Views of the Applicant

In its submission Canadian Superior estimated that the prorated oil allowable of the pool would range from 4,900 barrels per day during 1971 to 6,800 barrels per day in 1975. With good production practice at the proposed rate limitation of 6,000 barrels per day, the impact on the prorated oil market was claimed to be not unreasonable. In its closing remarks at the hearing the applicant noted that since the time of preparing the application substantial improvements have occurred in the crude oil market, and if the improvements are sustained the proposed rate would have a negligible impact on the proration plan and may be less than prorated rates. Having regard for the change in market demand and the fact that no interventions were filed to its application the applicant requested that the Board consider establishment of good production practice without an oil rate limitation for the pool. The applicant further suggested that if the Board deems it necessary to set a rate limitation, a limit of 8,000 barrels per day be adopted except when the proratable allowable is greater.

(2) Views of the Board

The Board has considered Canadian Superior's request, contained in the closing remarks, to permit good production practice with either unrestricted oil production rates or a maximum limit to oil production of 8,000 barrels per day.

In spite of the fact that no interventions were filed to the application, the Board is concerned about accepting such an amendment in the last phase of the hearing. Nevertheless, the Board believes it must assess the potential oil recovery in relation to its impact on the proration plan and will not therefore limit its considerations to a maximum rate of 6,000 barrels per day.

Based on current Board estimates of demand and reserves for proratable Alberta crude oil, the oil allowable for the pool would average some 6,000 barrels per day in 1972 and increase during the next few years to in excess of 7,000 barrels per day. The Board recognizes that, if gas sales are permitted, much of the potential recovery would have to be achieved in the next 3 to 4 years when reservoir pressures are highest and productive capacity is available.

The initially proposed rate limitation of 6,000 barrels per day would have no impact on the proration plan and would likely be less than prorated allowable rates. The Board estimates that approving a rate limitation of 7,000 barrels per day would have an average impact of about 500 barrels per day on the proration plan over the next two to three years and would provide a gain in oil recovery of 0.8 million barrels.(1) Increasing the production rate to 8,000 barrels per day would add a further 0.6 million barrels(1) to the recovery but would increase the impact to some 1,200 barrels per day for the next three to four years. As stated previously the Board has some reservations about granting good production practice because of coning problems, particularly at the higher production rates. The full recovery gain associated with a rate of 8,000 barrels per day may not be achieved. Having regard to the potential gain in recovery and the impact on the proration plan, the Board believes that a maximum rate limitation of 7,000 barrels per day is reasonable and should be adopted.

MODIFICATIONS TO THE GAS CAP CYCLING SCHEME

(1) Views of the Applicant

As intended in the original cycling program, Canadian Superior proposed to shift the cycling scheme toward the oil zone by producing gas from some currently suspended oil wells which produced with high gas-oil ratios and by converting to dry gas injection several existing gas producing wells which are producing mostly lean gas. It contended this would continue the sweep of raw gas toward the oil zone. Besides improving gas cap liquid recovery, this would improve pressure

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(1) These recovery gains are predicated on the gas production schedules applied for and would be somewhat less under the gas schedules approved by the Board.

response to the oil column and assist oil recovery. Replacement of reservoir voidage created by the cycle scheme would be continued.

(2) Views of the Board

The Board agrees that the modifications proposed for the cycling scheme would improve liquid recoveries and provide some pressure maintenance of the oil zone.

THE EFFECT OF THE GAS SCHEDULE ON RECOVERIES

(1) Views of the Applicant

The applicant demonstrated through various cases of reservoir depletion simulated by both 2-D and 3-D models that a gas schedule with the blowdown of the gas cap occurring prior to the total depletion of the oil zone would have adverse effects on both oil zone and gas cap liquid recovery, while marketable gas recovery would increase somewhat. This is illustrated in Figure 1 based on Cases I, II and VII which have 0-X-100:4000 programs.[1] It should be noted that Case VII was prepared by the applicant at the request of the Board from two slice model case and Case I together with some calculations made independently of the model studies. Liquid recoveries from the pool range from 97.3 million barrels with blowdown in 1972 to 120.6 million barrels, with blowdown deferred to 1987. Thus, by continuing cycling and deferring blowdown for 15 years, an additional 23.3 million barrels of liquids would be recovered. The applicant contended that deferral of blowdown to 1987 was not economically feasible. A schedule of 0-77-100:4000 would provide a recovery of 109.4 million barrels or an increase of 12.1 million barrels over the 0-72-100:4000 schedule indicating a progressively decreasing recovery as the blowdown time is deferred. Canadian Superior contended that liquid recovery would be near maximum by 1987.

The applicant investigated various alternative depletion programs for the purpose of approaching "optimization of both recovery of reservoir fluids and economic returns". As a first step it assessed the impact of instituting limited gas sales while continuing cycling operations to 1977. Canadian Superior concluded that this plan would result in higher recoveries than under immediate blowdown but lower recoveries than if gas is not sold during 1972 to 1977. The applicant then introduced a plan to produce the oil zone at rates in excess of prorated allowables which would significantly

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(1) "X" refers to the year in which cycling terminates and gas sales commence.

improve oil recovery. In a similar manner the applicant investigated and concluded that adoption of water flood operations in the northern part of the oil zone would ensure a substantial improvement in recovery. Also, the applicant planned to restrict gas withdrawals in the early years to the south-east segment of the gas cap in order to take advantage of the concentration of lean gas at a higher than average reservoir pressure in this area as discussed in a later section of this report. The concept of continuing cycling to 1977 permitting limited gas sales in the meantime from the south-east gas segment, accelerating oil production and implementing water flood operations in the northern oil segment were incorporated in the applicant's proposed scheme. Liquid recovery under the proposal was estimated by Canadian Superior to be greater than the case assuming immediate blow-down and the case assuming continuation of full cycling operation for a further five years with gas sales commencing in 1977.

(2) Views of the Board

The Board agrees with the applicant's estimate of liquid recovery for those cases where blowdown occurs in 1972 or in 1977 but does not fully agree with the estimate where blowdown occurs in 1987. In the Board's view the extended cycling period in the latter case would result in the recovery of more condensate than the applicant estimated. As shown in Table 1 and illustrated in Figure 1, the applicant estimated total condensate production of 39.8 million barrels for Case 0-87-100 compared to 38.4 million barrels for Case 0-77-100. Based on its calculations, the Board is satisfied that an increase of only 1.4 million barrels for 10 years of additional cycling is too conservative and that a more realistic estimate of condensate recovery for Case 0-87-100 would be 43.0 million barrels. For similar reasons the Board believes that the estimate of crude oil recovery should be increased by 1.6 million barrels to 58.0 million barrels. The Board accepts the applicant's estimate of butanes and propane recoveries for the 0-87-100 case but has adjusted the marketable gas recovery from 600 billion cubic feet at 1500 psig abandonment pressure to 700 billion cubic feet at 1000 psig abandonment pressure.

The Board observes that the increase in liquid recovery as the blowdown date is deferred is virtually linear until around 1980 but thereafter the rate of increase declines, particularly in the later 1980's. Thus, in general, from a recovery point of view, blowdown should be deferred as long as possible. The Board recognizes the interplay of economic considerations however, and as indicated later agrees with the applicant that the 0-87-100 case is not a realistic objective.

The Board also considered the impact on liquid recovery of permitting limited gas sales while cycling operations continue. While the Board drew heavily on data submitted by the applicant, it had to use its judgment in estimating recoveries for cases in which only the gas schedule was modified. Because of the "optimizing" approach taken by Canadian Superior most of the cases presented contained changes in more than one operating condition and were not readily comparable. The Board adjusted all of the pertinent cases presented by the applicant to reflect water flood operations in the northern segment and a maximum oil production rate of 6,000 barrels per day(1) under good production practice. In addition, by interpolation, the Board developed several cases employing different gas schedules.

Cases 0-72-100 and 0-87-100, as adjusted, are shown in Table 3 and provide, in the Board's opinion, upper and lower limits of recoveries from the pool. Recoveries for Case 50-77-134, which is the applicant's proposed scheme of operations, are unchanged from the submission. Case 0-77-100 is a case presented by the applicant but adjusted in the previously described manner, whereas Case 40-82-125 was developed by the Board.

Figure 2 gives the estimated liquid recovery versus blowdown date for different production schedules. While the data are limited, particularly for cases other than zero gas sales prior to blowdown, they indicate the magnitude of the improvement in recovery resulting from deferment in the date of blowdown. The figure also demonstrates the degree to which recovery declines with increasing gas sales prior to blowdown, although the varying sales rates after blowdown tend to exaggerate the differences. It is apparent from Figure 2 that alternative gas schedules can yield the same liquid recovery. For example, a total recovery of 122 million barrels may be obtained by the 0-77-100 case, or the 30-78.5-118 case or the 50-82-134 case.

Table 3 also shows the marketable gas production for the above cases. The figures show that gas recovery decreases slightly with deferment of blowdown. The Board's confidence in these figures is limited but the range of recovery is a small percentage of the total. In any case, decreased gas

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(1) Earlier in the report, the Board concluded that a rate of 7,000 BOPD should be approved, however the calculations regarding the effect of different gas schedules were made on the basis of the applied for rate of 6,000 BOPD. The Board is satisfied that the estimated recoveries based on a rate of 7,000 BOPD would not be significantly different.

recovery must not be considered to be entirely disadvantageous because at a given final reservoir pressure it is better to have the reservoir pore space occupied by dry gas rather than by liquids or wet gas.

ECONOMIC CONSIDERATIONS AND CONSERVATION

(1) Views of the Applicant

Cash flow and present worth analyses were presented by Canadian Superior for Cases I to VII to demonstrate the effect of various operational programs on conservation and economics. Two modifications of Case VI, referred to as Cases VIA and VIB were filed, at the Board's request, following the hearing. These cases incorporated water flood operations in the northern segment and a crude oil production rate of 6,000 barrels per day, thus facilitating the comparison of cases 0-72-100 and 0-77-100 with the proposed case 50-77-134. In the present worth analyses the applicant used a discount rate of 10 per cent.

The applicant contended that water flooding the northern segment would improve both recovery and economics. Similarly recovery and present worth would be improved by accelerating the rate of oil production over that permitted under the proration plan.

With respect to the continuation of cycling operations and blowdown of the gas cap, the applicant, by means of Exhibits 10 and 12, demonstrated that continued cycling operations would result in a greater liquid recovery and cash flow but a lower present value. Canadian Superior's assessment of the effect of limited gas sales while cycling operations were continued indicated that for a given year of blowdown, as the sales rate increased, recoveries and cash flow declined while present worth increased.

Canadian Superior submitted that its proposed operational program represented a near optimum scheme for the pool. By continuing gas cap cycling until 1977, recoveries would be enhanced and by concurrently permitting limited gas sales, present worth would be improved. The applicant contended that the Board should have regard for the economic worth of the gas cap as compared to the conservation gain in liquid recoveries as well as having consideration for the different participation of oil and gas owners in the Harmattan-Elkton Unit No. 1.

The applicant pointed out that the partial gas sales volume would not be produced at an even rate throughout the year but would be delivered primarily in the winter period for peak shaving purposes. This approach would not only provide efficiencies within the gas industry but would also ease the current winter condensate oversupply to the extent of some 10,000 barrels per day because the lean cycled gas would reduce the wet gas production from pools in Alberta.

With respect to the matter of ceasing cycling operations, Canadian Superior submitted that blowdown of the gas cap should begin in 1977. A large portion of the gas cap liquid would, by that time, have been recovered through the cycling program. Furthermore, it would result in a near maximum cash flow and the oil recovery losses would be within tolerable economic and conservation limits. Canadian Superior contended that the cash flow would not increase much after the proposed 1977 blowdown time but that there would be a significant decrease in present worth.

(2) Views of the Board

The Board concurs with the applicant that recovery and economic considerations indicate that water flood operations should be instituted in the northern oil segment of the pool. The Board also believes that an increase in the maximum oil production rate would enhance liquid recovery if gas sales were permitted. Therefore, in considering the interplay of recovery and economics as affected by the gas sales schedule, the Board has assumed that the water flooding and increased oil production rate portions of the application would be granted. The Board also used the applicant's assumption that the partial sales gas would be taken from the south-east segment. The Board's view on the latter assumption is discussed later.

With respect to the selection of an appropriate gas schedule it is apparent that there is a conflict between physical conservation and economic objectives. Physical conservation would be enhanced by deferring the blowdown date to about 1987, whereas the economics of the plan would be enhanced by earlier blowdown. In order to assess these conflicting objectives and to assist in determining a reasonable balance between them, the Board adjusted several of the cases submitted by the applicant and developed several additional cases. Reference has already been made to the method of adjusting the recovery estimates in order that all pertinent cases would be based on water flood operations in the northern segment and an oil production maximum rate limit of 6,000 barrels per day.

In preparing the economic evaluations of these cases, the Board believes that it must recognize to some degree the probability of future price increases for petroleum products and increasing operating costs. Accordingly, the Board has assumed crude oil and condensate prices which increase at 2.5 per cent per annum and propane and butanes prices increasing at 2.0 per cent per annum. Marketable gas prices were assumed to increase by 5 cents per thousand cubic feet (MCF) after the first nine years of the contract, and thereafter at 2.5 cents per MCF at the end of each 5-year period, in addition to the usual increments of 0.25 cents per MCF per year. For those cases with partial gas sales for peak shaving, a further premium of 5 cents per MCF was included in those years prior to blowdown. Operating costs were increased at 2.5 per cent per annum. In addition, the Board has applied a present worth discount rate of 8 per cent which it believes is more appropriate than the 10 per cent used by the applicant.

Figure 3 illustrates the present worth associated with various gas schedules based upon the assumed price and cost schedules. The lower curve shows the present worth assuming no gas sales prior to blowdown. The data for the other cases with gas sales prior to blowdown are limited but the impact on present worth is illustrated for 30-X-118 and 50-X-134 gas schedules for the period 1977 to 1982. In addition, the estimated present worth of a 40-82-125 case is depicted. The cash flow and present worth of the more pertinent cases shown in the figure are also presented in Table 3. In comparing the various cases, the Board examined not only the present worth and recovery figures, but also the cash flow figures which are a reflection of the total value of the produced hydrocarbons. However, since varying the gas schedule has a similar effect on cash flow as on physical recovery, the Board has limited its discussion to the relationship of physical recovery versus present worth income.

The lower curve in Figure 3, which depicts present worth at varying blowdown dates with no prior gas sales, clearly demonstrates the unfavorable impact on present worth of deferring blowdown. The figure also illustrates the substantial improvement in present worth achieved by permitting gas sales while cycling operations continue. It is apparent that a gas sales schedule of 30-82-118 would provide a present worth somewhat greater than the immediate blowdown case of 0-72-100. Further gains in present worth are noted for a

40-82-125 case and a 50-82-134 case, but both are less attractive than the proposed 50-77-134 case.

Figure 4 combines the physical recovery and present worth projections of Figures 2 and 3 for the 0-X-100 gas schedules and shows the recovery and present worth estimates for the 50-77-134, 50-82-134, 40-82-125 and 30-82-118 gas schedules.

As stated previously, the deferment of blowdown to 1987 would provide the highest liquid recovery of 133 million barrels but the lowest present worth of 116 million dollars. While this scheme would result in an ideal level of recovery the Board agrees that the cost of achieving it would be excessive.

The proposed 50-77-134 case yields an improvement in recovery of 5 million barrels over the immediate blowdown case of 0-72-100 and an improvement in present worth of 10 million dollars. The gain in recovery represents only about one quarter of the difference between immediate blowdown and blowdown in 1987. The present worth appears to the Board to be about the maximum attainable from any operational program for the pool. Having regard for the limited improvement in recovery and the virtual maximization of present worth, the Board cannot accept the proposed 50-77-134 gas schedule as representing a suitable balance between physical recovery and economic objectives, i.e. reasonable conservation.

The Board has considered three gas schedules in which cycling operations would terminate in 1982. These are depicted in Figure 4. The liquid recoveries and the present worth values corresponding with these schedules are shown below. The gas recovery is estimated to be some 720 BCF for each case.

Gas Schedule	Liquid Recovery Million Barrels	Present Worth Million Dollars
50-82-134	122	144
40-82-125	124	141
30-82-118	126	138

The Board appreciates the uncertainty inherent in these estimates but believes the relative values are satisfactory.

Each of these gas schedules would result in the recovery of approximately one half of the potential additional 21 million

barrels that could be achieved under a maximum physical conservation objective, as compared to immediate blowdown. With respect to present worth, the three cases provide returns that are either the same as or better than would be obtained under immediate blowdown. In general, the Board considers that these gas schedules represent a reasonable balancing of physical recovery and economics. The Board recognizes that there is not a great deal of difference among these alternative cases. The 30-82-118 case provides the best recovery, whereas the 50-82-134 case offers a recovery near the minimum that the Board considers reasonable. Having regard for the inherent uncertainties in the estimates, the Board believes that the 40-82-125 schedule is appropriate.

The Board is prepared therefore to approve a gas schedule providing for the immediate sale of gas at a rate of 40 million cubic feet per day and for the continuation of cycling operations until about 1982 following which gas sales at a rate of about 125 million cubic feet per day would be permitted. The Board believes that it would be better to determine the precise date of blowdown and the precise final sales rate following an assessment of the results of operations after a few years.

THE AREA FROM WHICH SALES GAS SHOULD BE PRODUCED

(1) Views of the Applicant

Prior to full blowdown, the applicant proposed to take the sales gas from the updip south-east segment of the gas cap which contains lean gas at a higher than average pool pressure. This would lessen the pressure effect on the wet gas area and oil zone and therefore offer better liquid recovery than removal of the gas downdip. In addition, the lean gas production would allow the construction of a relatively low cost processing plant, and the continuance of full cycling through present facilities.

(2) Views of the Board

The Board agrees that the south-east part of the gas cap is the best area from which to take sales gas prior to blowdown. In this way, recovery losses can be minimized by taking advantage of pressure gradient effects in the reservoir and by allowing continued cycling at current rates. Examination of the data presented by the applicant shows that the dry gas front could be unfavorably distorted as a result of marketing gas from the south-east segment. However, this problem can be overcome by adjusting actual field operations to provide for more wet gas production from the

area concerned. The Board believes that Section 18, Township 31, Range 3, West of the 5th Meridian and Sections 13, 24 and 25, Township 31, Range 4, West of the 5th Meridian are appropriate for dry gas production.

DECISION

The Board grants approval of a scheme of production of oil and gas from the Harmattan-Elkton Rundle C Pool, effective January 1, 1972, as follows:

1. The oil accumulation and its associated gas cap may be concurrently produced in accordance with Board Approval No. 1543 being issued simultaneously with this decision.

2. Annual gas sales shall not exceed 14.6 billion standard cubic feet of pipe line gas and shall be produced from the southeast segment of the gas cap at daily maximum rates as approved by the Board.

3. Gas cycling of the gas cap in accordance with Board Approval No. 967 and modifications approved by the Board shall continue until about 1982 following which cycling may be terminated and gas sales would increase to about 125 million cubic feet per day, with the precise year and final sales rate to be determined following assessment of performance and an application to the Board.

4. The oil shall be produced in accordance with good production practice subject to a pool crude oil maximum rate limitation of 7,000 barrels per day.

5. Pressure in the northern segment of the pool shall be maintained by the injection of water in accordance with Board Approval No. 1538, being issued simultaneously with this decision.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

DATED at Calgary, Alberta
June 25, 1971

ENERGY RESOURCES CONSERVATION BOARD

CANADIAN SUPERIOR'S REVISED
ATTACHMENT No. 1 OF EXHIBIT No. 5
APPLICATION No. 5396

TABLE 1 TO DECISION 71 - 12

SUMMARY OF DATA AT ABANDONMENT (1000 PSIA APPROX.)
HARMATTAN-ELKTON FIELD
ALBERTA, CANADA

	Case I 0-77-100:4000 #	Case II 0-71-100:4000	Case III 30-77-118:4000 GPP	Case IV 30-77-118:4000	Case V 0-72-95:GPP	Case VI 50-77-134:6000 GPP-WFN	Case VII 0-87-100:4000
CUMULATIVE PLANT PRODUCTS, Bbls							
Condensate	30,326,094	27,591,561	25,772,861	31,255,544	21,578,761	32,130,980	27,200,000
Butane	10,270,882	9,247,999	10,285,461	10,307,778	9,633,090	10,007,645	10,654,000
Propane	13,147,844	11,691,958	12,910,692	13,175,768	11,800,053	14,464,422	13,671,000
Total Plant Products	53,744,820	48,531,518	48,969,014	54,739,090	43,011,904	56,603,047	51,525,000
CUMULATIVE OIL ZONE PRODUCTS							
Oil, Bbls	47,510,260	42,537,843	44,535,243	45,431,715	48,212,477	54,648,733	56,400,000
Condensate, Bbls	8,137,722	6,270,750	11,151,891	6,881,877	11,550,493	5,501,637	12,600,000
Gas Produced, MMCF	402,509	328,237	552,735	340,569	608,358	252,313	NA *
Water Produced, Bbls	5,322,002	4,076,197	6,745,976	4,575,215	7,562,798	9,597,623	NA *
Water Injected, Bbls	10,354,838	8,075,347	10,812,236	8,914,996	11,570,804	73,545,038	NA *
Net Water Injected, Bbls	5,032,836	3,999,150	4,066,260	4,339,781	4,008,006		
Total Oil + Oil Zone Condensate, Bbls	55,647,982	48,808,593	55,687,134	52,313,592	59,762,970	60,150,370	69,000,000
TOTAL FIELD HYDROCARBONS							
Oil + Oil Zone Condensate + Plant Condensate, Bbls	85,974,076	76,400,154	81,459,995	83,569,136	81,341,731	92,281,350	96,200,000
Oil + Condensate + Butane + Propane, Bbls	109,392,802	97,340,111	104,656,148	107,052,682	102,774,874	116,753,417	120,600,000
Cumulative Net Gas Produced, MMCF	812,035	814,124	799,514	817,548	795,613	822,198	678,000
Residue Gas Sales, MMCF	711,495	721,021	704,487	719,153	700,070	725,668	599,472
GAS CAP							
Cumulative Gas Produced, MMCF	900,170	780,061	674,792	964,371	481,429	1,056,309	NA *
Cumulative Gas Injected, MMCF	490,644	294,174	428,013	487,392	294,174	486,424	NA *
CHARACTERISTICS OF CASES							
Oil Allowable, STB/D	4,000	4,000	4,000	4,000	None after 1-1-71	2,200 + 3,800	4,000
Oil Zone Gas	Minimum	Minimum	Maximum	Minimum	Maximum		Minimum
Blowdown Time	1-1-77	1-1-71	1-1-77	1-1-77	1-1-71	1-1-77	1-1-87
Residue Gas Sales Rate, MMCF/D	100	100	30 to 1-1-77;118	30 to 1-1-77;118	95	50 to 1-1-77;134	100
Workovers (Oil Zone)	Yes	Yes	No	Yes	No	Yes	Yes
Oil Rate at Abandonment, Bbls/D	460	310	425	710	270	1,183	720
System Pressure at Abandonment, psia	975	955	990	965	985		
Date of Abandonment	12-31-96	12-31-90	12-31-91	12-31-92	12-31-91	12-31-91	

\# THE BOARD'S CODE FOR DESCRIBING GAS AND OIL PRODUCTION PROGRAMS OF THE CASES.

* The gas and water figures are not considered significant to warrant extraction from computer printouts

ENERGY RESOURCES CONSERVATION BOARD

TABLE 2 TO DECISION 71 - 12

HARMATTAN-ELKTON RUNDLE C POOL
COMPARATIVE OIL ZONE RESERVOIR PARAMETERS AND RESERVES FROM CANADIAN SUPERIOR SUBMISSION AND AS ESTABLISHED BY THE BOARD

	Northern Segment		Total Pool	
Parameter	Canadian Superior	Board	Canadian Superior	Board
Oil Zone Rock Volume (acre-feet)	119,000	118,000	364,000	360,000
Area (acres)	-	4,000	11,200	11,100
Thickness (feet)	-	29.5	-	32.4
Porosity	.13	.128	.1235	.124
Water Saturation	.154	.20	.144	.20
Shrinkage	.68	.68	.68	.68
Oil in Place (million STB)	68.7	64.0	203.0	188.0
Primary Recovery Factor	.20	.20	(.223)	.28
Primary Recovery (million STB)	14.0	12.8	45.6 *	52.7
Residual Oil Saturation	-	.35		
Areal Sweep Efficiency	-	.70		
Vertical Sweep Efficiency	-	.75		
Incremental Waterflood Recovery Factor	.13	.10	(.044)	(.034)
Incremental Waterflood Recovery (million STB)	9.0	6.4	9.0	6.4
Total Recovery (million STB)	22.9	19.2	54.6	59.1
RFM (waterflood)	-	-	-	1.11

* Case V1 recovery to a pool abandonment pressure of 1237 psig

ENERGY RESOURCES CONSERVATION BOARD

TABLE 3 TO DECISION 71-12

SUMMARY AND COMPARISON OF RECOVERIES AND ECONOMICS FOR KEY CASES
HARMATTAN-ELKTON RUNDLE C POOL

		BOARD ESTIMATES* AT 6000 GPP-WFN				CANADIAN SUPERIOR'S ESTIMATES					
									RECOVERIES		
CASE	BOARD CODE	CASH FLOW $ MILLION	PRESENT WORTH 8% DISCOUNT $ MILLION	TOTAL LIQUID RECOVERY MILLION BARRELS	SALES GAS BCF	CASH FLOW $ MILLION	PRESENT WORTH 10% DISCOUNT $ MILLION	PRESENT WORTH 8% DISCOUNT $ MILLION**	TOTAL LIQUID MILLION BARRELS	MARKETABLE GAS BCF	OPERATING CONDITIONS
11 & V1B	0-72-100	284	138	112	721	210	99	108	110	690	6000 GPP-WFN
V1	50-77-134	307	148	117	726	228	102	113	117	726	6000 GPP-WFN
1	0-77-100	325	130	122	712	215	75	86	109	712	4000
X	40-82-125	339	140	124	720	-	-	-	-	-	-
V11	0-87-100	377	116	133	700	215 (252)	62 (61)	71 (75)	121 (125)	599 (700)	4000 4000

BRACKET FIGURES ARE ADJUSTMENTS TO APPLICANT'S ESTIMATES BY THE BOARD

* BASED ON ESTIMATED FUTURE INCREASES IN CRUDE OIL, CONDENSATE, PROPANE, BUTANES AND RESIDUE GAS PRICES AS WELL AS INCREASING OPERATING COSTS. RECOVERIES NORMALIZED TO CONDITIONS OF GOOD PRODUCTION PRACTICE AT A LIMIT OF 6000 BOPD WITH WATERFLOODING OF THE NORTHERN SEGMENT.

** APPLICANT'S CASH FLOW DISCOUNTED AT 8% BY THE BOARD.

NOTE: RECOVERIES ARE BASED ON DEPLETION OF THE RESERVOIR TO APPROXIMATELY 1000 PSIG
TOTAL LIQUID RECOVERY INCLUDES CRUDE OIL, CONDENSATE, PROPANE AND BUTANES.

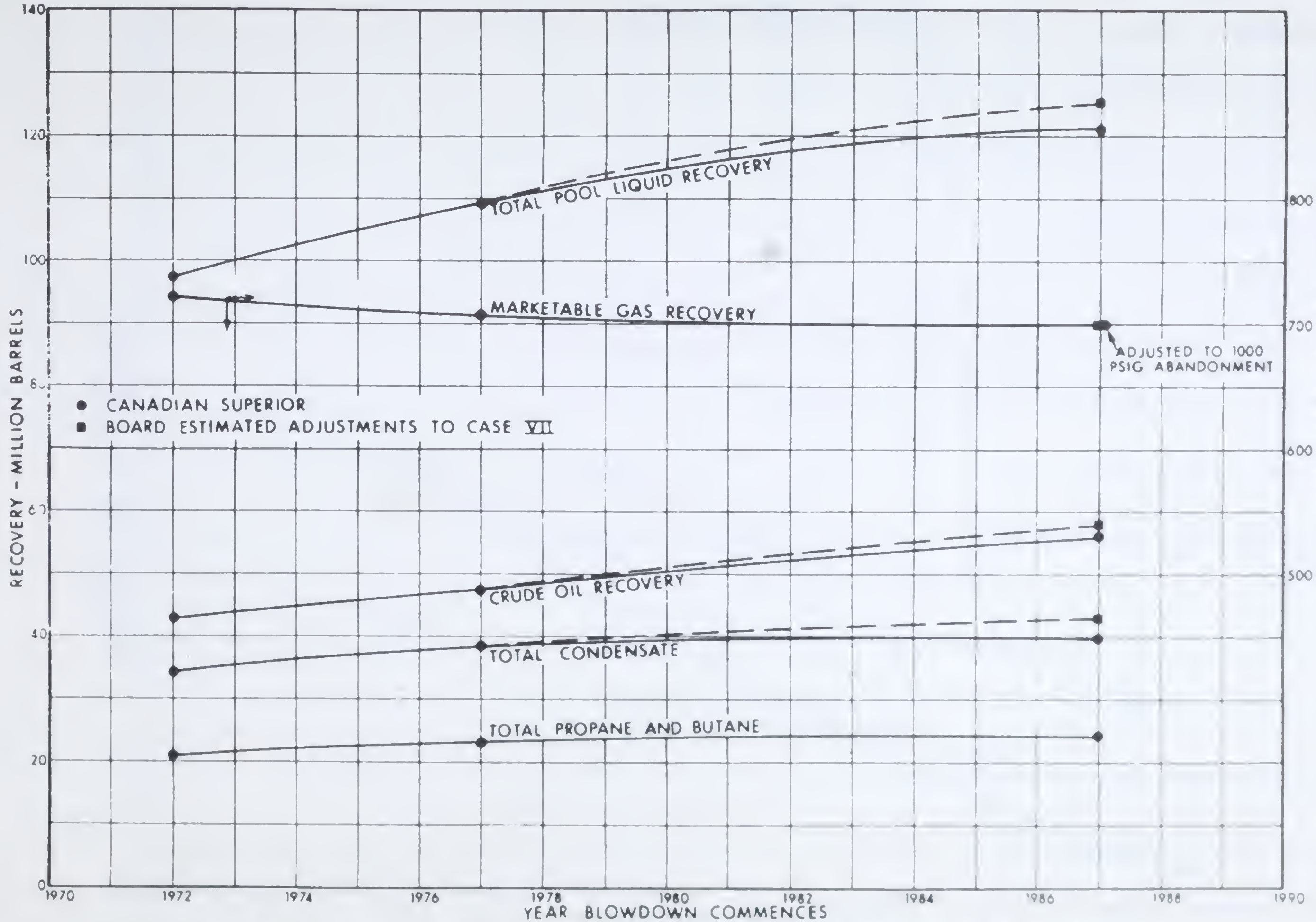

FIGURE 1 TO DECISION 71-12–EFFECT OF BLOWDOWN TIME ON LIQUID RECOVERY
0-X-100:4000 CASES
HARMATTAN - ELKTON RUNDLE C POOL

ENERGY RESOURCES CONSERVATION BOARD
CALGARY ALBERTA

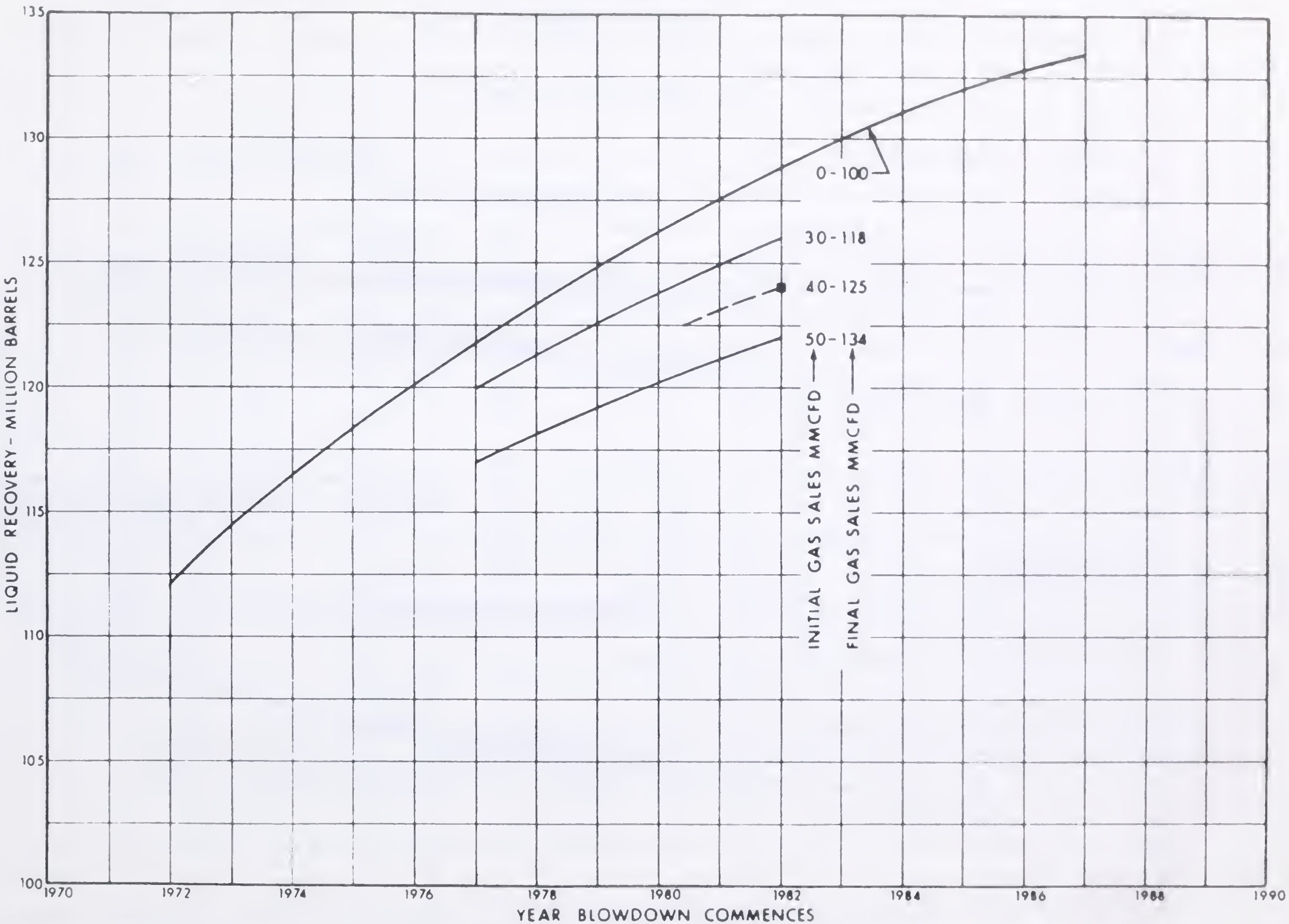

FIGURE 2 TO DECISION 71-12–THE RELATIONSHIP OF LIQUID RECOVERY AND THE GAS SCHEDULE
6000 GPP – WFN CASES

ENERGY RESOURCES CONSERVATION BOARD
CALGARY ALBERTA

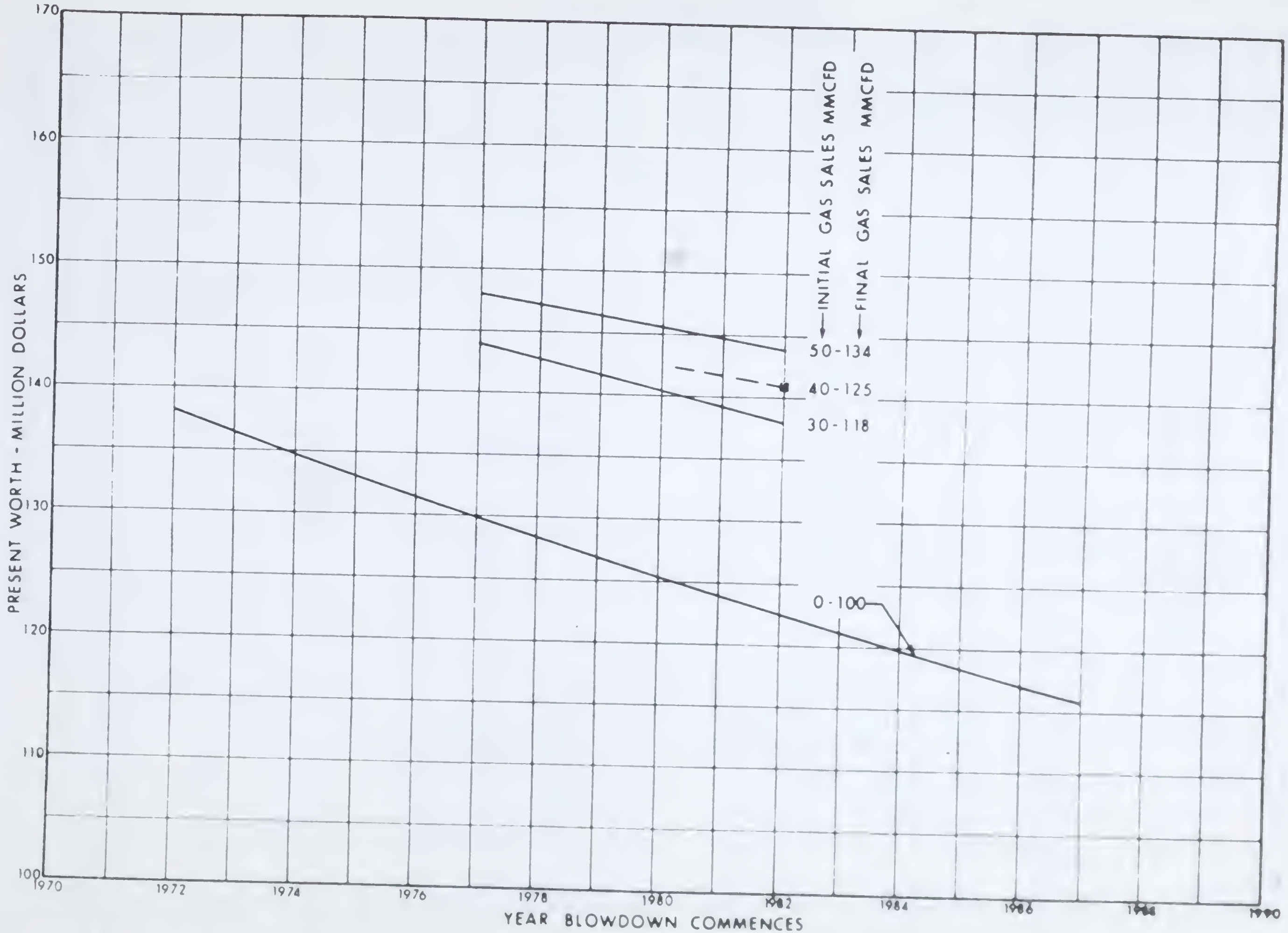

FIGURE 3 TO DECISION 71-12 - THE RELATIONSHIP OF PRESENT WORTH AND THE GAS SCHEDULE
6000 GPP - WFN CASES

ENERGY RESOURCES CONSERVATION BOARD
CALGARY ALBERTA

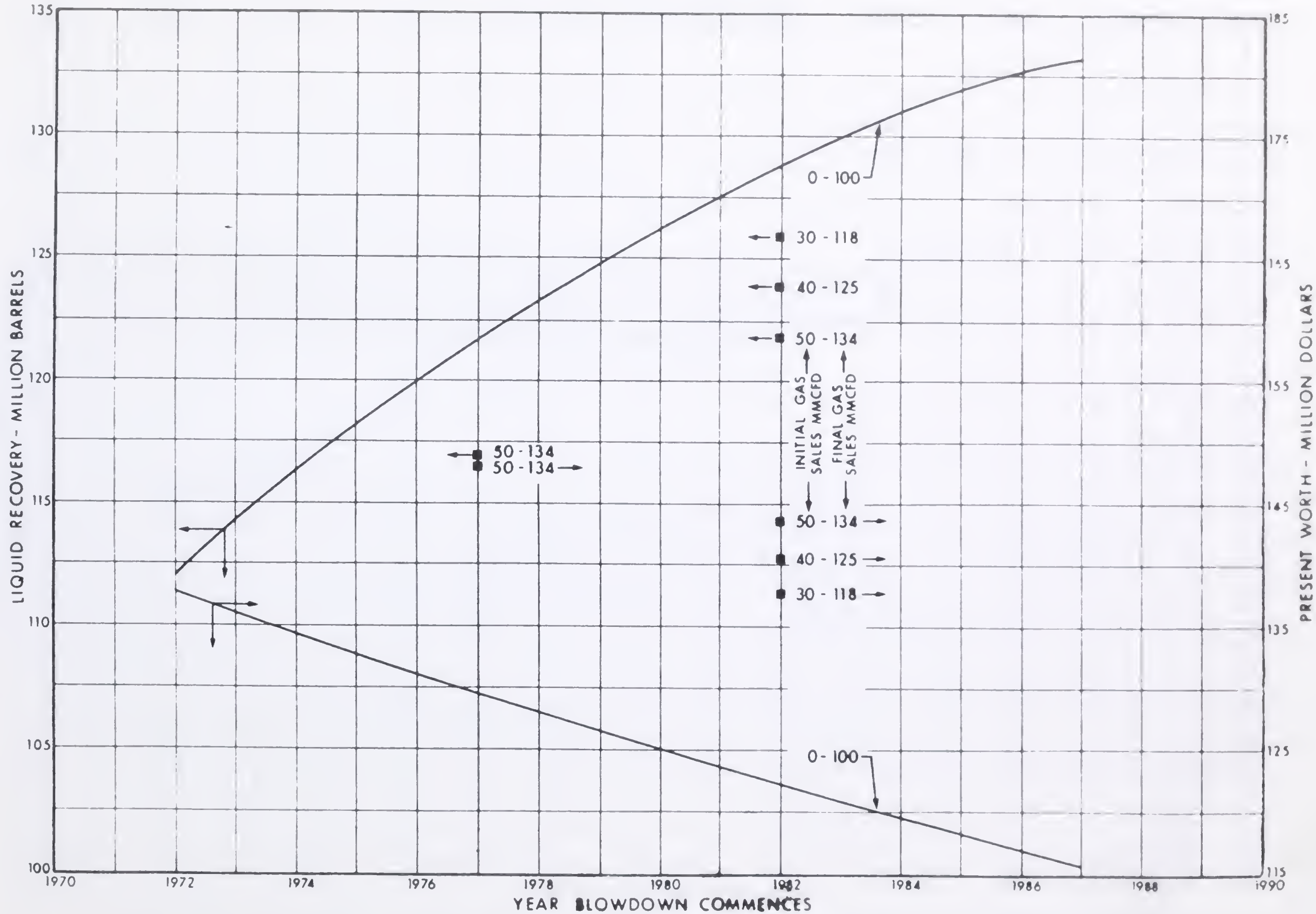

FIGURE 4 TO DECISION 71-12–THE RELATIONSHIP OF RECOVERY, PRESENT WORTH AND GAS SCHEDULE
6000 GPP - WFN CASES

ENERGY RESOURCES CONSERVATION BOARD
CALGARY ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

Decision 71-13
Application No. 5231

RECOVERABLE RESERVES
PEMBINA CARDIUM POOL

THE APPLICATION AND HEARING

Imperial Oil Limited submitted an application dated July 3, 1970, with respect to the ultimate recoverable reserves of the Pembina Cardium Pool.

Following meetings with the Oil and Gas Conservation Board, the applicant and major Pembina operators, it was agreed that the application was of sufficient importance that a hearing of it should be held by the Board at a date that would provide for adequate time to allow the Pembina operators to prepare an intervention to the application. The hearing was initially advertised for January 12, 1971, and following further representations by some Pembina operators, was deferred until March 2, 1971.

Imperial submitted a revision to its application on February 8, 1971. In its revised application, Imperial contended that the ultimate recoverable reserves of the Pembina Cardium Pool should be established at 1,302 million stock tank barrels.

The amended application provided Imperial's views respecting the reserves of the primary and water flood areas of the Pembina Cardium Pool. Imperial accepted the subsisting Board values for the solvent flood areas of the pool and individual company predictions of the recoverable reserves for the gas flood areas. Imperial's amended application included an estimate of 1,051 million stock tank barrels for the ultimate recoverable reserves of its interpretation of the water flood depletion area of the pool. At the hearing Imperial presented rebuttal evidence which further revised its application and resulted in an ultimate recoverable reserve of 968 million stock tank barrels for the water flood portion of the Pembina Cardium Pool.

Amoco Canada Petroleum Company Limited, in a submission filed jointly with Mobil Oil Canada Limited, submitted an intervention in which they submitted that the ultimate recoverable reserves of the Pembina Cardium Pool should be 2,117 million stock tank barrels.

Several other interventions covering parts of the Pembina Cardium Pool were filed by various operators.

The application was heard on March 2, 3, 4 and 5, 1971, by the Board, with G. W. Govier, P. Eng., A. F. Manyluk, P. Eng. and V. Millard sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Imperial Oil Limited	D. P. Bossler, P. Eng. W. B. Baker, P. Eng. W. G. Fisher, P. Eng. (of D & S Petroleum Consultants Ltd.) Dr. J. Archer	Imperial
Amoco Canada Petroleum Company Ltd. and Mobil Oil Canada Ltd.	G. E. Little E. E. Morris, P. Eng. Dr. F. F. Craig W. W. Owens C. T. Broughton, P. Eng. H. Groenveld, P. Eng. S. K. Bhatia, P. Eng. R. A. George	Amoco-Mobil
Great Plains Development Company of Canada, Ltd.	I. Ruus, P. Eng.	Great Plains
Gulf Oil Canada Limited	T. E. Randall, P. Eng. C. H. Gemroy, P. Eng.	Gulf
Mobil Oil Canada, Ltd.	D. D. Brown, P. Eng.	Mobil
Pacific Petroleums Ltd.	B. Geerlings, P. Eng.	Pacific
Supertest Investments and Petroleum Limited	R. A. Beamish, P. Eng. D. J. Bobyn, P. Eng.	Supertest
Tenneco Oil & Minerals, Ltd.	K. A. Heer, P. Eng.	Tenneco
Board Staff	J. A. Bray, P. Eng. D. N. Blades, P. Eng.	

BACKGROUND

The Pembina Cardium Pool, large in both areal extent and ultimate reserves, is a very heterogenous reservoir, undergoing depletion by several mechanisms. The ultimate recoverable reserve of the pool at year end 1964, 1965 and 1966 was studied extensively by Imperial and by the Pembina operators. These studies over the years have resulted in general agreement between Imperial and the Pembina operators as to the recoverable reserves for the area of the pool, excluding undrilled acreage, undergoing primary depletion. For the gas flood and solvent flood areas the parties have essentially accepted the Board set ultimate reserve figures as of December 31, 1970.

In all of these evaluations, including the application and interventions, the major difference in predicted ultimate recoverable reserves

has been for the water flood area of the pool undergoing depletion. This difference has continued to be in the range of 600 to 800 million barrels of recoverable reserves and results from the assumptions concerning the area studied, stratification of the reservoir, relative permeability and residual oil data, fluid productivity, the economic limits and the interpretation of production performance.

The submissions of the applicant and the interveners at the hearing included an additional four years of production performance.

The basic differences are dealt with as issues under the following headings:

1. oil in place

2. performance prediction methods

3. comparison of recovery predictions with performance

4. economic limit

5. recoverable reserves

OIL IN PLACE

(1) Views of Imperial

Imperial stated that it calculated the pore volume of the Pembina Cardium Pool by assignment of porosity and net pay values to each of the approximately 2,000 cored wells in the pool which were analyzed with the conventional plug method by Core Laboratories Inc. Each of the core analyses was compared to logs to determine whether the entire pay interval had been cored. For those wells with core analyses having short intervals missing, an interpretation of the porosity and permeability for the missing interval was made from the logs. The core analyses having fairly long intervals missing were rejected. A permeability cut off of 0.1 millidarcies was applied to the core data to determine net pay.

Imperial presented a connate water saturation-porosity correlation for the pool from oil-base cores obtained from 23 wells. The correlation was used to determine a connate water saturation of the individual plugs represented by the core analyses. Hydrocarbon pore volume values were calculated for each well studied and plotted and contoured for the entire pool.

Imperial categorized the saturation pressures in the pool on a "patch" map in eight pressure ranges on the basis of initial producing gas-oil ratios and a relationship derived from the saturation pressure and flash gas-oil ratio for 40 bottom hole fluid sample analyses. Areas of constant initial gas-oil ratios, and consequently saturation pressures, were plotted and contoured to show the distribution of fluid properties in the pool. Relationships between the reservoir fluid formation volume factor,

oil viscosity and gas in solution, determined as a function of pressure, were used to assign reservoir fluid properties to each "patch".

Imperial calculated the oil in place at the saturation pressure for each section in the water flood and the primary depletion areas of the pool by applying the appropriate reservoir fluid properties to the hydrocarbon pore volume as determined from the contoured map described above. The oil in place values for the solvent depletion schemes in the pool assigned by the Board were accepted by Imperial and the values for the gas flood depletion schemes were obtained from the appropriate operators. Imperial's evaluation of the water flood area and the corresponding oil in place at the saturation pressure was 356,320 acres and 5,408 million stock tank barrels respectively. The primary depletion area (not including water flood schemes without a recovery factor modifier or undrilled tracts) and saturation pressure oil in place were calculated to be 90,640 acres and 1,044 million stock tank barrels. Imperial stated that it assumed a 1.3 per cent recovery of the oil in place from original conditions to saturation pressure conditions.

(2) Views of Amoco-Mobil

Amoco-Mobil assigned net pay, porosity-footage and permeability-footage values to all wells in the Pembina Cardium Pool through the use of complete core analyses where these data were available and in the remaining cases incomplete core data or log data. A permeability cut off of 0.1 millidarcies was used to determine net pays. Iso-pore volume and iso-capacity maps were constructed for the pool from these data.

A connate water saturation versus porosity correlation was developed from an analysis of core samples having a water saturation greater than zero and which were obtained from wells drilled with an oil filtrate fluid. The minimum connate water saturation was arbitrarily established at four per cent.

Amoco-Mobil used the results from 53 bottom hole fluid sample analyses to divide the pool into five areas each with a unique set of reservoir-fluid properties.

The net pay, porosity-footage and permeability-footage for the wells in each section or partial section in the water flood area were combined to obtain a section average value. Amoco-Mobil modelled each section into a 40 layered model as described later in the report. To obtain the hydrocarbon pore volume of a section, a connate water saturation as determined from the connate water saturation versus porosity correlation was assigned to each layer. A summation of the layer hydrocarbon pore volumes resulted in a total for the section.

Amoco-Mobil submitted a calculated oil in place at the saturation pressure by applying the appropriate reservoir fluid properties to each section. By summing the oil in place for the individual sections in

the water flood area, estimated by Amoco-Mobil to be 354,640 acres, an oil in place at the saturation pressure of 5,648 million stock tank barrels was calculated. Amoco-Mobil also assumed, as did Imperial, that 1.3 per cent of the original oil in place was recovered to the saturation pressure. Amoco-Mobil accepted the oil in place values recognized by the Board as of December 31, 1970, for the primary depletion area and the areas subject to other depletion mechanisms in the pool.

(3) Views of Gulf

Gulf submitted that for the area of Project No. 85 in the Pembina Cardium Pool, the oil in place as calculated by Imperial is higher than that calculated by Gulf.

(4) Views of Tenneco

Tenneco stated that it used the iso-pore volume map, reservoir fluid properties and the connate water saturation versus permeability relationship established by Pan American Petroleum Corporation in the submission to the Board entitled "Ultimate Reserves Submission - Water Flood Area and Marketable Gas Reserves - Pembina Cardium Pool - February 1967" to calculate the oil in place for the two Pembina Cardium Projects No. 25 and 32 considered in its submission.

(5) Views of the Board

The Board recognizes that the two methods of calculating oil in place used by Amoco-Mobil and Imperial are essentially unchanged from those presented to the Board by the Pembina Allowable Committee and by Imperial in 1965 and 1966 and by Pan American Petroleum Corporation and Imperial in 1967. The Board notes the main difference in the evaluation of oil in place is that Imperial uses log data to confirm that the core analyses used in its studies represent the entire net pay in wells and to assign porosity and permeability only to short intervals where core was missing. Amoco-Mobil on the other hand used log data where no core data were available to assign net pay, porosity-footage, and permeability-footage values to each well in the pool.

It is the Board's opinion that the number and distribution of the wells analyzed by Imperial is adequate to obtain a representative pore volume for the pool. The Board considers that the Amoco-Mobil method of assigning log determined parameters to wells which do not have complete or near complete core data is, in principle, capable of giving more refined results than the Imperial method. In practice, however, recognizing that there are problems in obtaining representative data from logs, the Board doubts that the final result of the Amoco-Mobil approach is significantly more accurate than that of Imperial.

The Board adjusted the Imperial and Amoco-Mobil oil in place figures to the area of the pool in which water flood schemes were operating as of December 31, 1970. All oil in place values were then adjusted to original conditions by assuming that 1.3 per cent of the original oil in

place had been produced to the saturation pressure. The adjusted area covers 357,920 acres for which the Imperial oil in place value was adjusted to 5,500 million stock tank barrels and the Amoco-Mobil oil in place value was adjusted to 5,750 million stock tank barrels. The two adjusted oil in place values are within 4.5 per cent of each other. Since the Board considers either of the values equally reliable, it adopts an average value of 5,630 million stock tank barrels as the oil in place value for the water flood area of the pool.

The Board divided the oil in place value for the water flood area among those projects in the pool with a water flood recovery factor modifier as of December 31, 1970 and those water flood projects operating under a primary allowable. These oil in place values were calculated to be 5,220 million stock tank barrels and 410 million stock tank barrels respectively. The Board notes that the oil in place value determined for the water flood area of the pool with a recovery factor modifier represents a decrease from the value of 5,530 million stock tank barrels recognized by the Board on December 31, 1970.

In evaluating the oil in place values submitted for the primary depletion area of the pool, the values were adjusted to original conditions and that area of the pool not included in an enhanced recovery scheme as of December 31, 1970. The adjusted Imperial values were 88,800 acres and 1,050 million stock tank barrels. The Board noted that Amoco-Mobil accepted the primary oil in place figures currently set by the Board for the primary area of the pool. Since the Board primary depletion value includes enhanced recovery scheme areas which do not have a recovery factor modifier, the Amoco-Mobil value is too high for this area.

The Board notes that Imperial did not include a primary reserve assignment to any undrilled areas of the pool. Previous evaluations of the pool reserves have included estimates of recovery which would be obtained from undrilled tracts of the pool and the Board value for recoverable reserve includes recognition of this area.

The Board's evaluation of the original oil in place for the primary depletion area of the pool was 1,300 million stock tank barrels. A comparison of the Board and the Imperial evaluations results in a difference equivalent to that previously recognized for the undrilled areas of the pool. The Board therefore concludes that the primary oil in place of 1,700 million stock tank barrels set for the pool, as of December 31, 1970, should be retained since this value is consistent with the oil in place calculated for the primary depletion area, including undrilled acreage, plus the oil in place established for the water flood schemes with a primary allowable.

The following table summarizes the oil in place and acreage values submitted by each operator, the Board values set for December 31, 1970, and those values accepted by the Board subsequent to the hearing and referenced by the date June 1, 1971.

ORIGINAL OIL IN PLACE

(oil in place - million stock tank barrels)

DEPLETION MECHANISM	BOARD DECEMBER 31, 1970	IMPERIAL	AMOCO-MOBIL	BOARD JUNE 1, 1
PRIMARY				
Oil In Place	1,700*	1,058	1,690*	1,290
Acreage	114,406	90,640	114,560	87,960
WATER FLOOD (RFM)				
Oil In Place	5,530	5,480**	5,722**	5,220
Acreage	325,920	356,320	354,640	325,920
WATER FLOOD (NON-RFM)				
Oil In Place				410
Acreage				32,000
GAS FLOOD				
Oil In Place	43	100	43	43
Acreage	7,360	7,040	2,726	7,360
SOLVENT FLOOD				
Oil In Place	472	472	472	472
Acreage	17,680	17,680	17,680	17,680
POOL TOTAL				
Oil In Place	7,740	7,110	7,927*	7,440
Acreage	465,366	471,680	489,606	470,960

* includes enhanced recovery schemes not assigned a RFM (recovery factor modifier)
** total water flood depletion area

PERFORMANCE PREDICTION METHODS

Imperial and Amoco-Mobil made predictions of the recoverable oil under water flood for large portions (about 600 square miles) of the Pembina Cardium Pool. Gulf studied in detail two sections of Pembina water flood (Project No. 85) operated by it. Mobil created ten hypothetical reservoirs, characterized by a Dykstra-Parsons (1) "variance factor" and applied the prediction that most closely matched the production performance of each Mobil operated water flood section of the Pembina Cardium Pool. Tenneco studied its Projects No. 25 and 32, using the Amoco-Mobil prediction technique.

(1) Views of Imperial

Imperial's reservoir model incorporated a mathematical average capacity distribution curve, calculated from representative core analyses for each section. Sand and conglomerate pay were treated separately but both were assigned pay to a lower cut off of 0.1 millidarcies. In those sections not containing conglomerate, Imperial chose to represent the reservoir by 10 layers of equal porosity thickness (Øh). Where conglomerate was present Imperial represented the reservoir by 20 equal Øh layers, 10 each for the sand and the conglomerate.

Imperial applied the Carter water flood prediction technique to each section of the reservoir modelled as described above. The method assumes that each pore-volume layer is non-communicating in the inter-well region. Recovery from each layer is related to the linear recovery and relative injectivity curves which are functions of the total displaceable volumes of injection to the layer. The curves are adjusted for area conformance by the Higgins and Leighton method (2). The ultimate recovery from the well or section, is determined at an estimated economic limiting water-oil ratio at the producing well. Imperial stated that if identical data were used, the Carter prediction technique "gives the same predicted performance as the method proposed by Craig, Geffen and Morse (3)" used by Amoco-Mobil.

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(1) Dykstra, H. and Parsons, R. L. "The Prediction of Oil Recovery by Water Flood", Secondary Recovery of Oil in the United States, Second Edition (1950), API

(2) Higgins, R. V. and Leighton A. J., "A Computer Method to Calculate Two Phase Flow in Any Irregularly Bounded Porous Medium", Trans. AIME (1962), P. I 679.

(3) Craig, F. F., Geffen, T. F. and Morse, R. A., "Oil Recovery Performance of Pattern Gas or Water Injection Operations from Model Tests", Trans. AIME, 204, (1955), p. 7.

In previous studies of the Pembina Cardium Pool, Imperial used weathered core to obtain the linear recovery and injectivity data. Inasmuch as these data differed significantly from steady state test data on weathered core, used by Amoco (previously Pan American), Imperial drilled a well to obtain some preserved core for reservoir condition water flood tests. Imperial discarded some of the preserved core plugs because of water saturations which, if considered, were too high due to the occurrence of water breakthrough in a twin well and other core plugs because of mechanical failure during testing. Seven tests on preserved core were used to establish the displacement and injectivity curves used for study.

Imperial expressed the view that the main difference between the preserved core tests and the weathered core tests was in the residual saturations. The shapes of the relative permeability curves from the two types of tests were similar. The preserved cores were found to be slightly water wet at porosities of 12 per cent or less. Imperial stated that these results were in contrast to previous work on preserved Pembina Cardium core which indicated that the reservoir rock was preferentially oil wet.

Preliminary investigation of the preserved core using the steady state method indicated residual oil saturations comparable to those obtained from dynamic displacements, but the shape of the steady state relative permeability curves suggested a more efficient displacement. Imperial rejected the steady state data on the basis that the use of such data in prediction calculations would require a larger adjustment than would the use of data from dynamic displacement in order to match reservoir performance.

Imperial stated that the minimum residual oil saturation it used was extrapolated to the recovery that would be obtained at an infinite throughput of water.

(2) Views of Amoco-Mobil

Amoco-Mobil expressed the opinion that Imperial's submission contained insufficient discussion of the tests conducted to assess the effect of assigning stratification on the basis of permeability and is "completely void of other sensitivity work on stratification". Amoco-Mobil stated that Imperial's representation of the reservoir by equal Øh layers was not appropriate for the prediction of breakthrough time and early performance history.

Amoco-Mobil stated that the largest single difference between itself and Imperial in the ultimate predicted recovery relates directly to the relative permeability data used. Amoco-Mobil disagreed with Imperial in its continued use of recovery and injectivity curves developed from unsteady state tests even though they were made on preserved cores at reservoir conditions. Amoco-Mobil suggested that the preserved core may not have been at "native state" conditions at the time of testing because of water breakthrough prior to the coring operation. Amoco-Mobil also questioned the reliability of Imperial's unsteady state test data with regard to the effect of the viscosity of the oil used in the displacement

tests on the results.

Amoco-Mobil used the Craig, Geffen and Morse stratified water flood prediction technique. It completed 8 comparisons of the Imperial and Amoco-Mobil prediction techniques and concluded the "comparisons were considered sufficient proof of the continued consistency of the two prediction techniques". The method assumes non-communicating layers in the inter-well bore region. Injection rates and areal sweep in the water contacted portion were determined by the method of Caudle and Witte [(4)].

Amoco-Mobil applied its prediction model to each section or partial section of Cardium formation subject to water flood, having first accounted for 1.3 per cent of the original oil in place as representing production of oil above the saturation pressure.

Amoco-Mobil modelled each section studied into a layered system generally using two or more completely cored wells. All permeability and porosity data from the cored wells were arranged in descending order of permeability. From these data a permeability-footage versus porosity-footage distribution curve was obtained. Amoco-Mobil concluded from trials of several approaches that the use of 30 or 40 layers of equal permeability thickness resulted in the best prediction of breakthrough but agreed that the ultimate recovery would essentially be the same as that obtained by modelling the reservoir with equal porosity-footage layers.

The relative permeability data applied to the water invaded regions in Amoco-Mobil's prediction method were derived from 20 preserved plugs taken from four wells cored with "Black Magic" oil base mud. The plugs were tested at ambient temperature under steady state conditions. Since there was no apparent correlation of the water-oil relative permeability curves obtained from the tests to porosity, permeability or initial water saturation, one average water-oil relative permeability curve was selected. The residual oil saturation was 35 per cent of pore volume for porosities of 20 per cent or greater decreasing to about 20 per cent of pore volume at 8 per cent porosity.

(3) Views of Supertest

Supertest questioned Imperial's "arbitrary decision to use dynamic water flood test data in preference to steady state data", and stated that Imperial should have attempted to explain the discrepancy between predictions and performance on the basis of stratification and areal conformance. The other interveners did not specifically question Imperial's prediction method or the data which it employed.

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(4) Caudle and Witte, "Production Potential Changes During Sweep-out in a Five Spot System", Trans. AIME, 216 (1959), p. 446.

(4) Views of Mobil

Mobil used a model employing variance factors as described by Dykstra and Parsons to predict ultimate recovery from the Mobil operated projects, but recommended that most weight should be given to the Amoco-Mobil recoverable reserves predictions.

(5) Views of Gulf and Tenneco

Gulf and Tenneco independently predicted the ultimate recoverable reserves from small Pembina Cardium water flood leases, operated by the two companies. Gulf supported Imperial's prediction with respect to Gulf's Project No. 85. Tenneco, using Amoco-Mobil's prediction technique, stated that the recoverable reserves of its Projects No. 25 and 32 "are considerably higher than Imperial's submission of May 6, 1970, indicates".

(6) Views of the Board

The Board agrees with Imperial and Amoco-Mobil that, given the same or equivalent basic data, and applied to equivalent reservoir layers, the Carter and the Craig-Geffen-Morse non-communicating layer prediction techniques would provide very nearly identical predictions of oil recovery versus producing water-oil ratio. The difference in the Imperial and Amoco-Mobil predictions results both from the use of certain different basic data and from the choice of different methods of representing the variation of porosity and permeability with pay thickness.

With respect to the basic data used by Imperial and Amoco-Mobil, the principle differences are in the residual oil saturations and in the effective relative permeability or its equivalent. The applicant and interveners questioned each other at some length respecting these data but the Board was not provided with any new or conclusive evidence to permit it to conclude which of Imperial's or Amoco-Mobil's displacement data was actually or theoretically superior.

The recovery at breakthrough, and the subsequent relationship between producing water-oil ratio and recovery, are sensitive to both the porosity and the permeability stratification. Where stratification is extreme, as in the Pembina Cardium Pool, the Board would expect the performance to be better predicted, especially at, and immediately following breakthrough, by a representation of the reservoir through 40 rather than 10 or 20 layers. Furthermore, the equal permeability-thickness (Kh) layering should, in principle, be more suited to the prediction of the recovery at breakthrough since the early breakthrough phenomenon results from high permeability streaks.

Actual performance data, to be discussed later, indicate that, on the average, Amoco-Mobil predicts breakthrough at a recovery somewhat too high. Accepting as the Board does that Amoco-Mobil's 40 Kh layering technique should be superior for breakthrough prediction, the failure of Amoco-Mobil to predict the actual recovery at breakthrough indicates to the Board that the basic relative permeability data used by Amoco-Mobil

must be in error in the direction resulting in a high recovery prediction. On the other hand the Imperial layering prediction of recovery at breakthrough is, on the average, too low while the converse would be expected if the relative permeability or equivalent data were correct. This suggests to the Board that the Imperial displacement data are in error in the direction which results in a low recovery prediction.

COMPARISON OF RECOVERY PREDICTIONS WITH PERFORMANCE

(1) Views of Imperial

To facilitate a comparison of performance with predictions, Imperial plotted both the producing water-oil ratio versus the cumulative oil production history and the predicted performance for each of 398 sections in the pattern water flood area. The original Imperial application was revised to include production history to December 31, 1970. Imperial interpreted that 186 sections were performing worse than predicted, 75 sections were performing as predicted, 33 sections were performing better than predicted and 104 sections had insufficient history to make a comparison. The results of the comparison were included in a study which illustrated that the trend over the last ten years indicates a greater increase in the number of sections performing "worse than" than in the number of sections performing "better than". Imperial concluded on the basis of the large number of sections in which performance did not match its predictions that "adjusting the predictions on the basis of performance is one solution to this particular problem".

The adjustment used by Imperial was a horizontal shift of the prediction curve to make it match performance. Imperial submitted that the adjustment would probably result in a high reserve since early performance history was considered to be optimistic. It contended that this results from sections having excess productive capacity and wells having high water-oil ratios which in many cases are produced at a minimum.

Imperial contended that the performance of individual wells demonstrates recovery trends at a higher water-oil ratio level and that these data substantiate the curve shift. In its application, Imperial stated that an adjustment of the oil in place until performance matches the recovery prediction may be more appropriate. This approach was used by Imperial to adjust the prediction of 30 to 40 sections, the results of which were included in its rebuttal document as a decrease in its recoverable reserves.

In examination Imperial agreed that it had not accounted for oil production from the period at the saturation pressure to commencement of water flooding. Imperial stated that this resulted in approximately a 1.4 per cent recovery error in plotting history. The resultant adjustments summarized in Imperial's rebuttal document indicated a shift in the section classification to indicate generally better performance than previously observed. These adjustments were used to increase its ultimate recoverable reserves estimates.

Imperial contended that an evaluation of the modified line drive water flood projects in the Berrymore, Lindale and Keystone area of the pool showed water flood performance which could be expected at higher water-oil ratios. The Imperial evaluation involved a consideration of the water-oil ratio and recovery from wells at various distances and consequently water-oil ratios, from injection wells. The oil recovery from a well was calculated from the water-oil ratio versus cumulative injection curve. This method assumes that no production was taken from a well after it had reached breakthrough conditions. The effective water injection to any well was calculated from the total water injected minus the water produced behind the well. From these data a water-oil ratio versus recovery curve was constructed for four points up to and including a water-oil ratio of ten. On the basis of this study, Imperial concluded that approximately one-half of the predicted reserves would be recovered from the line drive areas.

Imperial submitted that 65.6 per cent of the 218 primary depletion sections reviewed indicated worse performance than that predicted while 13.3 per cent indicated better performance. Since sufficient history data were not available in all of the sections, adjustments to reserves based on performance were made in the Keystone area of the pool. Sections in this area were divided into three gas-oil ratio groups in order to match performance with predicted recoveries. The analysis indicated that 54 of the 64 sections were performing worse than predicted. Reserves in these sections were adjusted by the amount of difference between the performance curve and the predicted curve.

(2) Views of Amoco-Mobil

Amoco-Mobil submitted that Imperial's conclusion, that performance in the water flood areas of the Pembina Cardium Pool indicated a lower recoverable reserve, resulted from the use of an inadequate stratified model to predict early breakthrough history. It also contended that Imperial's classification of the performance of each section was not considered to be valid since no classification guidelines were presented, little consideration was given to performance trends subsequent to breakthrough, many of the sections classed as having insufficient history have recoveries in excess of that predicted, the 398 sections considered by Imperial do not represent the total pattern water flood area and the history data presented by Imperial was plotted from the commencement of water flooding rather than from the time saturation pressure was assumed to be reached.

Amoco-Mobil classified the comparison of predicted and actual performance for sections presented by Imperial into seven groupings. In addition to the Imperial classifications, Amoco-Mobil also included "early breakthrough but a satisfactory current trend", "not enough history but satisfactory current trend" and "not enough history but unsatisfactory current trend". It concluded that approximately 13 per cent of the sections were performing "worse than", 68 per cent of the sections were performing "the same as" or "better than" and 19 per cent of the sections had "insufficient history" for comparison.

Amoco-Mobil stated that the Imperial shift of the predicted recovery curve to match performance was "arbitrary and inconsistent as applied" since the curve was shifted to match just breakthrough conditions in many cases. It stated the belief that there is generally insufficient history to support a shift since 65 per cent of the adjustments were made to sections with a water-oil ratio of less than one, that current history indicates early breakthrough does not necessarily indicate poorer than predicted reserves, that Imperial's stratified model was not adequate to describe early performance, and that many sections were classed as "insufficient history" where breakthrough recovery exceeds that predicted.

Amoco-Mobil introduced evidence at the hearing to show that oil production has increased in the pool by approximately 50 per cent since 1967 with no indicated increase in water-oil ratio which it contended demonstrated that low water-oil ratios are not the result of operational flexibility, as suggested by Imperial.

Amoco-Mobil presented plots of predicted performance versus actual performance for the 632 sections or partial sections in the water flood area. Since it was considered that no satisfactory quantitative method of comparing performance with predictions was available, the sections were not classified into general groups. An analysis of the breakthrough time was considered to be significant in assessing the accuracy of the prediction method. It was concluded that in 407 of the 632 sections studied, the water breakthrough time was adequately predicted, indicating an excellent match. The current water-oil ratio and water-oil ratio trend was examined for each of the sections to evaluate the curve shape and the factors such as relative permeability which affect the curve shape and it was concluded that 537 of the 632 sections were adequately matched by the predictions. Amoco-Mobil submitted that the predictions adequately match performance history to date and confirm its ultimate reserves of the pool.

(3) Views of Great Plains

Great Plains submitted that Imperial's prediction technique did not properly represent the recovery performance for the Great Plains sections classed as "worse than" and therefore a shift of the prediction curve to match performance was not valid. Great Plains stated that for the sections which they operate and which Imperial classified as "insufficient history" it would classify the sections as "as predicted" or "better than".

(4) Views of Gulf

Gulf supported Imperial's submission and stated that for its Pembina Cardium Project No. 85 area Imperial's recovery factors agree with those calculated by Gulf.

(5) Views of Mobil

Mobil expressed disagreement with Imperial's method of shifting the prediction curves to match performance and demonstrated for its properties that performance could be matched by calculating recovery predictions using its Dykstra-Parsons "variance factor" technique.

(6) Views of Pacific

Pacific contended that Imperial's method of classification of sections was not defined and therefore was subject to a high degree of interpretation. Pacific evaluated its operated properties and submitted that three of nine sections could be shifted to an improved classification. It was pointed out that Imperial used breakthrough and early performance history to adjust ultimate predicted reserves without technical substantiation.

(7) Views of Supertest

Supertest submitted that Imperial in its analyses of the 398 sections did not give sufficient weight to the water-oil ratio trend subsequent to breakthrough in adjusting predicted performance to actual performance. A reclassification by Supertest of the sections presented by Imperial and taking into account water-oil ratio trends since breakthrough resulted in a more optimistic evaluation of water flood performance to date. Supertest submitted that Imperial's prediction technique was inadequate in that it failed to predict breakthrough performance.

(8) Views of the Board

The Board compared the individual section recovery predictions of both Amoco-Mobil and Imperial with performance to date in an attempt to determine which prediction resulted in the better match. The Board's evaluation was confined to the 398 sections in Imperial's application. This number of sections is considered to be representative of the water flood performance of the whole pool since they provide a reasonable representation of the whole pool and include the majority of the mature water flood schemes in the pool. The Board notes that as some 75 per cent of the sections do not have a water-oil ratio in excess of one, the only general comparison possible is one of performance at and immediately following breakthrough.

A qualitative review indicates to the Board that each of Imperial's and Amoco-Mobil's methods give closer comparisons in about 40 per cent of the sections with the remaining 20 per cent of the sections being matched about equally well by either prediction method.

An average breakthrough point was calculated for each of the prediction methods for the 398 sections in the pattern water flood area on a volume-weighted basis for comparison with the actual volume-weighted breakthrough point for the 398 sections as a whole. The analysis of the actual performance data to December 31, 1970, showed the average breakthrough

point at approximately 5.4 per cent recovery. Moreover, some 70 sections have not yet experienced breakthrough and the Board estimates that when all sections have shown breakthrough the actual average breakthrough point will be in the range of 5.5 to 5.6 per cent of oil in place. This latter figure may be compared with the Imperial and Amoco-Mobil predicted average breakthrough points of about 5.2 and 6.1 per cent respectively. (It should be noted that the Board interpretation of the Amoco-Mobil value may be slightly high due to the difficulty in defining the breakthrough point on many of the prediction versus performance plots). These values, coupled with the fact that section breakthrough conditions are governed by the performance of the worst well in a section, especially in sections containing no wells with excess productivity, indicate to the Board that the average actual recovery at breakthrough will be approximately midway between the predictions of Amoco-Mobil and Imperial.

The Board also compared the actual and the predicted recoveries at a water-oil ratio of approximately one for the limited number of sections (some 100) whose history has reached this ratio. It finds a scattering of the data below and between the two predictions. The Board would expect that sections at this water-oil ratio represent the worst cases and notes that the effect of these sections tends to be offset by those sections performing better than predicted at water-oil ratios below this level.

The Board attempted to evaluate the performance of those sections producing at a water-oil ratio in excess of about two. It notes that only about 6 per cent of the sections in the pattern water flood area have reached this level of water production. The Board does not believe it possible to draw meaningful conclusions from the performance of the high water-oil ratio sections when they represent such a small percentage of the pool.

The Board agrees with Amoco-Mobil that the number of layers used to describe stratification does not have a significant effect on predicting ultimate recoveries. The Board believes that the difference in the predictions at high water-oil ratios is primarily the result of the relative permeability (or the equivalent) and residual oil saturation data used in the respective predictions. Having concluded from the breakthrough performance analysis that the Imperial prediction is pessimistic and that the Amoco-Mobil prediction is optimistic, the Board believes that an average of the two predictions provides a more realistic estimate of the ultimate recovery than does either of them.

Imperial reduced the ultimate recoverable reserves to less than 10 per cent for the Lindale-Berrymore line flood areas on the basis of the performance reviews of wells immediately offsetting water injection wells. The Board notes that this region of the pool contains much conglomerate and is extremely stratified. The Board prediction at the time of the 1964 year end general Pembina reserve review was that recoveries in this area would range from 5 to 15 per cent of the oil in place. The Board concludes that the previously assigned reserves which are between the Imperial and the Pembina Allowable Committee or Pan American predictions for the Lindale-Berrymore area are still reasonable and not in conflict with the performance to date.

The Board reviewed the Imperial evaluation of recovery performance in the primary depletion areas of the pool and notes that the primary recovery factor of 8.4 per cent submitted by Imperial is not significantly different than the 8.6 per cent currently recognized by the Board. The Board is of the opinion that the sections under primary production and studied by Imperial are not necessarily representative of the primary area of the pool. The Board does not believe that there is sufficient new evidence, at this time, to warrant an adjustment of the primary recoverable reserve.

ECONOMIC LIMIT

(1) Views of Imperial

Imperial submitted that a study of operating costs for 12 Pembina Cardium Pool projects during 1966 and 1967 resulted in an actual operating cost of $389 per well per month. An additional cost of $75 per well per month was considered to be applicable due to the predicted long producing life of the pool which would result in all of the surface equipment and certain subsurface equipment being replaced at least once. This cost was calculated by assuming a depreciation of the initial investment of such equipment in the water flood area of the pool. Imperial divided the resultant total operating cost of $464 per well per month into a fixed cost of $314 per well per month and a variable cost of 10 cents per barrel of liquid produced. The relationship between fixed and variable costs was determined at a liquid production rate of 100 barrels per day. The Imperial economic limit data was adjusted to a producing well cost by assuming an injection to producing well ratio of 1 to 1 corresponding with a five-spot pattern.

Imperial calculated the economic limiting water-oil ratio by applying the economic limit data to a productivity forecast based on a five-spot configuration flow equation with a pressure drop of 4,100 pounds per square inch gauge. Imperial stated that this would result in high economic reserves due to the optimistic productivity forecast.

Imperial submitted additional evidence during the hearing to revise its previous economic limit data. The revised data included a decrease in the operating costs of $45 per producing well per month to account for gas gathering costs which are considered to be offset by gas revenues. The gas gathering costs were summed for each applicable project and the resultant cost was subtracted from the total operating costs of all the projects considered. Imperial stated that an injection well to producing well ratio of 1 to 2 was more representative of the pool average than the 1 to 1 ratio previously used. It was also contended, however, that a liquid production rate of 45 barrels per day was more appropriate than the 100 barrel per day rate used to establish the relationship between fixed and variable costs since the 45 barrel per day rate closely approximates current well average conditions. In its rebuttal document Imperial submitted that the economic limiting water-oil ratio should be calculated from actual productivities rather than from theoretical productivity calculations.

Imperial stated that the economic limit for the primary depletion sections was 5 barrels of oil per well per day.

(2) Views of Amoco-Mobil

Amoco-Mobil submitted that fixed and variable cost data presented by Imperial were unrealistically high and unrepresentative of the Pembina Cardium Pool. It stated that of the twelve projects studied by Imperial for cost data, one was not a water flood and two were line drive water floods and were therefore not representative of the pool. Amoco-Mobil contended that the depreciation cost should not have been included in the analysis since only operating costs will be considered at abandonment conditions.

Amoco-Mobil contended that the variable costs for produced liquids were estimated by Imperial in 1965 from limited areas of the pool and that it is unlikely that costs at that time could be considered to represent abandonment conditions. The inclusion of lifting costs in the variable costs was not considered appropriate since the total amount of liquids lifted should be about the same at abandonment as at present.

Amoco-Mobil submitted economic limit data based on the costs of operating 635 producing wells in the pool. The operating costs were summarized and broken down into a fixed cost of $436 per producing well per month and a variable cost of 2.88 cents per barrel of water injected. Included in the fixed cost was an overhead charge of $98 per producing well per month, an item which Amoco-Mobil suggested was usually not considered when examining the economics of abandoning individual wells. Amoco-Mobil stated that 6 per cent of the operating cost in its data represented an equipment replacement cost. Variable costs were defined as those associated with enhanced recovery and water disposal. A variable cost increase of 1.5 cents per barrel of water injected was applied by Amoco-Mobil to account for possible future increased water handling costs. The resultant variable cost submitted was therefore 4.38 cents per barrel of water injected. Amoco-Mobil stated that it expects crude oil price increases to more than offset future operating cost increases.

Amoco-Mobil presented a relationship between eight permeability capacity ranges and productive capacity used to construct a curve of economic limiting water-oil ratio versus permeability capacity. The curve was incorporated into the water flood prediction to obtain an economic limiting water-oil ratio for each section.

(3) Views of Great Plains

Great Plains stated that the costs presented by Imperial were not in agreement with its experience in operating wells in this pool. An average operating cost of the Great Plains properties was stated to be $520 per producing well per month including overhead costs. This total cost was subdivided into a fixed cost of $438 per producing well per month and a variable cost of 4 cents per barrel of liquid produced or 3 cents per barrel of water injected. Great Plains submitted that it would be unreasonable to include the cost of depreciation in determining economic limiting costs since generally major equipment will be replaced only when the investment will yield an attractive rate of return.

(4) Views of Gulf

Gulf stated that the economic limiting oil production rate used in its study of Pembina Cardium Project No. 85 was 5 barrels per day. This value was considered to be optimistic.

(5) Views of Supertest

Supertest contended that the Imperial analysis of the economic limit was unrealistic because of the use of the depreciation cost and the high variable operating cost. It submitted that the decision to abandon a well is made when current costs exceed revenue and therefore depreciation should not be considered. Supertest suggested that its experience indicated that the variable costs are the costs of chemicals to treat both injection water and produced oil and water and are in the order of 1 cent per barrel of liquid produced.

Supertest stated that Imperial should have recognized the actual producing well to injection well ratio rather than assuming a five spot 1:1 producer to injector ratio. The Imperial estimate of direct operating costs of $389 per well per month was considered to be realistic by Supertest.

(6) Views of Tenneco

In its study of recoverable reserves for Pembina Cardium Projects No. 25 and 32, Tenneco used the economic limit data presented by Pan American Petroleum Corporation to the Board in 1967, modified to include the December 1970 crude oil price increase.

(7) Views of the Board

The Board observes that the total operating costs submitted by Amoco-Mobil and Imperial are almost identical except for the special depreciation costs proposed by Imperial and when adjusted to an injection to producing well ratio of 1 to 2. The Board agrees with both Amoco-Mobil and Imperial that an injection to producing well ratio of 1 to 2 is a good approximation for the pool and should be used in determining the economic limit for the pool.

Although the basic methods of applying the cost data as an economic limit are similar in both cases, the Board has determined that there are three major differences in the Amoco-Mobil and Imperial evaluations as follows: depreciation costs, the determination of the variable cost and the productivity capacities used to calculate the economic limiting water-oil ratio.

The Board is of the opinion that, in the general case, wells will be abandoned when operating costs are approximately equal to current revenues. The Board, however, also recognizes that abandonments will take place prior to this point when equipment failures occur and anticipated future revenue will not yield a satisfactory rate of return on the cost of equipment replacement. Since it is impossible at this time to estimate

the actual amount of special equipment replacement costs which should be considered, the Board believes that it would be conservative but appropriate to consider one-half of the special depreciation cost proposed by Imperial to account for those wells which will be abandoned due to equipment failure.

The Board notes that Imperial amended the base liquid production rate used to determine the relationship between fixed and variable costs from 100 barrels per day to 45 barrels per day to reflect the liquid productivity of 50 per cent of the wells in the pool. The Board is of the opinion that the relationship between fixed and variable costs should be based on the current average water flood area liquid productivity of 80 barrels per day.

Having regard for the factors discussed above, the Board is of the opinion that a cost of $450 per producing well per month represents the fixed operating costs in the water flood area of the pool.

The Imperial variable cost provision of 10 cents per barrel of liquid produced includes surface pumping equipment, power and well servicing costs which are not considered by the Board to be completely variable costs. Excluding these costs from the Imperial data results in a variable cost of 5.68 cents per barrel. On the basis of the variable cost data submitted by Amoco-Mobil, Great Plains, Supertest and Imperial and the previously expressed Board opinion that variable costs should include mainly liquid handling and treating costs, the Board is of the opinion that the variable cost would be adequately represented by 5 cents per barrel of liquid produced.

The assumption that increasing crude oil prices will offset increasing operating costs is considered by the Board to be reasonable.

The Board considers the relationship between permeability capacity and productive capacity presented by Amoco-Mobil to be a valid approach in applying economic limit to individual wells since the data were obtained from field testing. The Board does not consider that current productive capacity is a valid measurement of ultimate productive capacity. This is supported by recent evidence that the total pool production has continued to rise with increased allowables and with the recent changes in underproduction regulations. The Board notes that the Imperial theoretically calculated productive capacities agree fairly closely with the Amoco-Mobil field data and accepts an average of these data as being representative of the ultimate section capacities.

The Board determined the economic limiting water-oil ratio for each section by evaluating the total liquid capacity and applying the variable and fixed cost data considered to be reasonable. The economic limiting water-oil ratio was calculated by the same method as that used by Amoco-Mobil and Imperial.

RECOVERABLE RESERVES

(1) Views of Imperial

The ultimate recoverable reserves for the Pembina Cardium Pool submitted by Imperial and reported in this section are those in its original application modified by its revision document of February 8, 1971, and further modified by its rebuttal document submitted at the hearing.

Imperial submitted that its prediction method resulted in an ultimate recoverable reserve of 1,213 million stock tank barrels for the area of the Pembina Cardium Pool considered by it to be under both pattern and line water flood. This value was calculated by summing the recoverable reserves determined at the economic limiting water-oil ratio for each of approximately 600 sections or partial sections in the water flood area of the pool. Imperial adjusted this value on the basis of the performance history of the 398 sections which it studied. Of the 398 sections, 104 had insufficient production history to warrant a curve shift. For these 104 sections Imperial used its analyses of water breakthrough and performance trends to group the sections into one of the performance classifications similar to those used to categorize the 294 sections. Imperial calculated that the "worse than" sections showed a negative recovery adjustment of 3.28 per cent and that the "better than" sections showed a positive recovery adjustment of 0.6 per cent, based on the total oil in place for the 398 sections studied. The net negative performance adjustment of 2.68 per cent, applied to the pattern water flood area, resulted in a reduction to the recoverable reserves of 126 million stock tank barrels.

Imperial submitted that its evaluation of the line water flood areas of the pool resulted in a negative reduction in the recoverable reserves of some 36 million stock tank barrels. Consequently, the ultimate recoverable reserve for the total water flood area was submitted to be 1,051 million stock tank barrels. This figure was further adjusted to include the evidence submitted in its rebuttal document.

In its rebuttal document the additional revisions included a positive adjustment of some 29 million stock tank barrels for oil production not previously considered from the saturation pressure to commencement of water flooding, a positive adjustment of some 81 million stock tank barrels to account for the costs and revenues associated with gas gathering, a negative incremental performance adjustment of some 32 million stock tank barrels due to matching the performance of several sections by adjustment of the oil in place, and a negative adjustment of some 160 million stock tank barrels to reflect actual productivities rather than the theoretical productivities previously used in evaluating the economic limiting water-oil ratio. Imperial submitted, therefore, that the ultimate recoverable reserves for the water flood area should be 968 million stock tank barrels.

Imperial shifted its prediction of the primary depletion area recovery curves in 54 sections to match performance and obtained a negative reserve adjustment of some 17 million stock tank barrels. This adjustment

was applied to the predicted recovery to obtain a recoverable reserve of some 87 million stock tank barrels.

Imperial accepted the Board set values of the ultimate recoverable reserves for the solvent flood areas and the operator's predictions of the ultimate recoverable reserves for the gas flood areas.

Combining these values resulted in a pool total ultimate recoverable reserve of 1,219 million stock tank barrels.

(2) Views of Amoco-Mobil

Amoco-Mobil submitted that Imperial's estimate of recoverable reserves in the water flood area of the pool was unrealistic because of its use of inadequate stratification and unrepresentative relative permeability and economic limit data in the model to predict performance and ultimate recovery.

Water flood recovery predictions were made by Amoco-Mobil for each of the 632 sections or partial sections in the water flood area of the pool. The total water flood recoverable reserves were calculated to be 1,811 million stock tank barrels. This value represents a recovery factor of 31.6 per cent and includes the primary recovery of 1.3 per cent from original conditions to saturation pressure conditions. Amoco-Mobil accepted the ultimate recoverable reserves currently designated by the Board for the other depletion mechanisms in the pool and submitted that the pool total ultimate recoverable reserves will be 2,117 million stock tank barrels.

Amoco-Mobil stated that laboratory tests and reservoir simulation studies indicated that oil will be recovered by pressure depletion after the completion of water flooding.

(3) Views of Great Plains

Great Plains submitted that it calculated an increase in the recovery factor of 4.1 per cent from that evaluated by Imperial for the Great Plains properties through the use of economic limit data analyzed for the properties and through recognition of recovery prior to commencement of flooding. It contended that by projecting the increase in recovery factor to the total water flood recovery submitted by Imperial would result in an increase in ultimate recoverable reserves of 230 million stock tank barrels for the pool.

(4) Views of Gulf

Gulf concluded that the water flood recovery factors calculated by Imperial for the area of Project No. 85 were in good agreement with those calculated by Gulf.

(5) Views of Mobil

Mobil expressed disagreement with water flood recovery estimates submitted by Imperial for the Mobil properties. On the basis of its

prediction method, Mobil contended that for these properties, the recovery factors should be approximately 40 per cent rather than the 25 per cent suggested by Imperial.

(6) Views of Pacific

Pacific submitted that Imperial was unable to provide "valid justification for revision of the ultimate water flood reserves in the Pembina Cardium Pool".

(7) Views of the Board

The Board adjusted the ultimate water flood recoverable reserves submitted by Imperial and Amoco-Mobil to the water flood area with a recovery factor modifier as of December 31, 1970. The ultimate water flood recoverable reserve of 1,213 million stock tank barrels initially predicted by Imperial was used in this evaluation. Adjusted ultimate recoverable reserves of 1,145 million stock tank barrels and 1,681 million stock tank barrels were calculated from the predictions of Imperial and Amoco-Mobil respectively.

As discussed previously, the Board concluded that the best prediction of the ultimate water flood recoverable reserves would be an average of the predictions presented by Imperial and Amoco-Mobil for each section in the entire water flood area. The Board calculated the predicted recoverable reserves from each section in the water flood area by applying the arithmetic average of the Amoco-Mobil and Imperial recovery prediction curves, at the appropriate economic limiting water-oil ratio, to the average oil in place presented for each section. The data used to calculate economic limiting water-oil ratios were discussed previously. By summing the ultimate recoverable reserves calculated for each section in the water flood area assigned a recovery factor modifier as of December 31, 1970, the Board obtained a reserve of 1,390 million stock tank barrels. This reserve is equivalent to a recovery factor of approximately 27 per cent, by coincidence the very value recognized by the Board as of December 31, 1970. The reduction in oil in place discussed earlier from 5,530 to 5,220 million stock tank barrels therefore results in a reduction in ultimate water flood recoverable reserves from 1,460 million stock tank barrels set on December 31, 1970 to 1,390 million stock tank barrels. The Board concludes that the value of 1,390 million stock tank barrels should be set as the ultimate water flood recoverable reserve.

The Board notes that Imperial adjusted its predicted recovery factor for the primary depletion area to 8.4 per cent and that Amoco-Mobil accepted the recovery factor of 8.6 per cent recognized by the Board on December 31, 1970. The Board is of the opinion that no evidence was presented at the hearing to warrant an alteration to the recovery factor of 8.6 per cent which results in an ultimate recoverable reserve for the primary area of 146 million stock tank barrels.

In the absence of any significant new evidence regarding the ultimate recoverable reserves assigned to the gas flood and solvent flood areas of the pool, the Board will continue to recognize the reserves

assigned to these depletion mechanisms as of December 31, 1970.

The following table summarizes the ultimate recoverable reserve estimates submitted by Imperial, Amoco-Mobil and established by the Board.

ULTIMATE RECOVERABLE RESERVES

(recoverable reserves - millions of stock tank barrels)
(recovery factor - per cent of original oil in place)

DEPLETION MECHANISM	BOARD DECEMBER 31, 1970	IMPERIAL	MOBIL	BOARD JUNE 1, 1971
PRIMARY				
Recoverable Reserves	146	87	146	146
Recovery Factor	8.6	8.4	8.6	8.6
WATER FLOOD				
Recoverable Reserves	1,460	968	1,811	1,390
Recovery Factor	27	17.1	31.6	27
SOLVENT FLOOD				
Recoverable Reserves	154	154	154	154
Recovery Factor	33	32.6	32.6	33
GAS FLOOD				
Recoverable Reserves	6	10	6	6
Recovery Factor	15	10.1	15	15
POOL TOTAL				
Recoverable Reserves	1,770	1,219	2,117	1,700
Recovery Factor	23	17.1	26.7	23

DECISION

On the basis of the evidence made available in connection with Proceeding No. 5231, the Board is satisfied that the ultimate recoverable reserves of the Pembina Cardium Pool should be set at 1,700 million stock tank barrels effective August 1, 1971. This number is comparable to the value of 1,770 million stock tank barrels set by the Board as of December 31, 1970, and does not reflect minor changes made in the reserves assigned to certain projects in the period January 1, 1971 to July 31, 1971. These changes have been recognized in recent MD Orders and will continue to be recognized in future MD Orders.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

DATED at Calgary, Alberta
July 6, 1971

ENERGY RESOURCES CONSERVATION BOARD

Decision 71 - 14
Application No. 5809

PARTS OF TURNER VALLEY RUNDLE POOL
SUBJECT TO UNIT OPERATION

INTRODUCTION

(1) Application and Hearing

Gulf Oil Canada Limited, the unit operator for Turner Valley Unit No. 5 and Turner Valley Unit No. 7 (Gas Cap), applied pursuant to The Turner Valley Unit Operations Act for amendment of Order No. TVU 3, Order No. TVU 4, Order No. TVU 5, and Order No. TVU 6 as to clause 1, subclause (1) of each order, and of Order No. TVU 7 as to clause 2, subclause (1). Subject to minor, immaterial differences in Order No. TVU 7, the first three lines of the subclauses referred to in the application read "All interests in the tracts within the Turner Valley Rundle Pool and within the lands hereinafter described are consolidated, merged and otherwise combined in a unit operation". The application was to have this part of the subclauses changed to read "All interests in that part of the Turner Valley formation of the Rundle group lying above the Turner Valley Sole Fault as described by W. B. Gallup, W. D. MacKenzie, T. A. Link and others in the Bulletin of The American Association of Petroleum Geologists Volumes 35, 24 and 18 respectively and within the lands hereinafter described are consolidated, merged and otherwise combined in a unit operation".

At the hearing it was pointed out that the remedy sought by the applicant would be ineffective unless the first two lines of the clause in each order following that referred to in the application were also changed. These two lines read "The unit is that portion of the Pool vertically beneath the lands described as follows:". The applicant stated that it would be prepared to amend its application to provide for a suitable change in these two lines.

The application was heard by the Energy Resources Conservation Board on August 6, 1971, with D. R. Craig, P. Eng. and V. Millard sitting.

(2) Appearances

The following appeared at the hearing:

	Represented by	Abbreviatio Used in Repo
Gulf Oil Canada Limited	G. A. McGuffin, P.Eng. G. A. Holland R. Rector	Gulf Canada
Home Oil Company Limited	F. R. E. Mulder, P.Eng.	Home Oil
Western Decalta Petroleum Limited	L. G. Elhatton J. D. Harper, P.Eng.	Western Decalt
Board Staff	J. A. Bray, P.Eng. L. A. Falkenberg, P.Eng. N. A. Macleod, Q. C.	

(3) Provisions of the Act

The Turner Valley Unit Operations Act in section 2, clause (e) states "pool" means the pool in the Turner Valley formation of the Rundle group within the Turner Valley Field, as that field is designated from time to time by the relevant subsisting order of the Board made pursuant to The Oil and Gas Conservation Act. Section 3, subsection (3) of the Act says, "If the Board after a public hearing is satsified that a unit operation would prevent waste, the Board may order that the part of the pool in respect of which the application is made, or as reduced or increased by the Board, be operated as a unit operation". Section 4, subsection (1) lists what may be included in an order under the Act and clause (b) reads "a description of the lands containing the unit". Section 5, dealing with a rehearing, states that the Board, following the rehearing, may amend or revise an order made under section 3 in order to supply any deficiency therein or to meet changing conditions, and may alter or revoke any provision that is deemed by the Board to be unfair or inequitable.

When the Act was enacted in 1958 it contained a preamble which was omitted in revision. The first paragraph of the preamble stated that "it appears that the ultimate recovery of oil and gas from the Turner Valley Field could be increased by the establishment of the unit operations in parts of the field".

BASIS OF APPLICATION

(1) Views of the Applicant

Gulf Canada submitted that the descriptions of the units in the orders has been adequate to describe the hydrocarbon accumulation fully developed by 1951 and presently producing

under the subject orders. Exploration is now contemplated by Gulf Canada which will encounter the Turner Valley formation in the regional sheet some 2000 to 5000 feet deeper than the present producing horizon. The applicant submitted that the amendment applied for would not be so much a change as a clarification of what was committed to each unit. Gulf Canada testified to a belief that if any of the parties to the proceedings leading to the formation of the units had any inkling at that time that there was some valuable production or a new pool underlying the present producing pool, they would have specifically excluded and reserved the part of the pool below the producing section.

The intention of the subject Act and orders, according to the applicant, was to implement secondary recovery rather than to provide for new exploration and development.

(2) Views of Home Oil

Home Oil stated that when the units were formed the basic intent was to unitize those parts of the Mississippian formation that were capable of producing at that time.

(3) Views of Western Decalta

Western Decalta stated that it generally supported the application.

(4) Views of the Board

When the units were formed attention was not drawn to the possibility of a reoccurrence of the Mississippian below the developed beds. The Board agrees with the applicant that, in light of the preamble to the Act when passed in 1958 and to the provisions of section 3, subsection (3), the purpose of the unit operation under the Act was to prevent further waste and enhance ultimate recovery from the pool then producing. The Board does not believe that any provision of the Act or the definition of the units in the orders subject to the application precludes the granting of the application. In view of the additional development that may result and the absence of objection by any of the owners of tracts within the units, the Board is prepared to amend the subject orders by redefining the units to meet the objective of the applicant in making its application.

DESCRIPTION OF PRODUCING PART OF THE POOL

At the hearing it was evident that all the parties were concerned about the problem of applying a new definition of a unit, if the application were granted, to the physical evidence that may be found in any new well that may be drilled through the productive part of the pool.

(1) Views of Applicant

Gulf Canada indicated that it would be prepared to accept a modification of the wording set out in its application along the lines suggested by the interventions filed by the other unit operators in Turner Valley. Examined as to the geological criteria that would be used to define the Turner Valley Sole Fault in any well that might be drilled, the applicant's witnesses stated that the sole fault would be the lowest fault and also the fault of largest displacement, that there would be considerable vertical displacement, that below the sole fault the well would penetrate a horizon other than the Mississippian and younger than it, and that in the area of the established Turner Valley units the developed part of the pool and the sole fault underlying it would be separated from any lower occurrence of the Mississippian by an interval. Further, the applicant submitted that if any dispute occurred in this area the matter would be decided by the Board, and that it would expect that there would be a difference in pressures in the two occurrences of the Mississippian to assist in making a decision.

(2) Views of Home Oil

In its intervention Home Oil submitted that, if the clauses referred to in the application were reworded, they should specifically reserve to the present units those formations in which any of the Turner Valley Unit wells are now completed. In his evidence Mr. Mulder, the Home Oil witness, suggested that a cut-off level of 5700 feet subsea could be incorporated into any new provision, as there is no well producing in the Turner Valley formation below that level at the present time.

(3) Views of Western Decalta

Western Decalta submitted that the proposed new wording should be expanded to specifically reserve to the Turner Valley Units "those formations or subsea intervals in which Turner Valley Unit wells are now completed". Upon cross-examination it agreed that the two words "formations or" could be deleted from its addition.

(4) Views of the Board

The Board agrees that any new definition of the units would be improved by a reference to the wells heretofore produced.

DECISION

The Board grants the application. For this purpose it will replace the subclause in the several orders and referred to in the application with the following:

"(1) All interests in the tracts within that part of the Turner Valley Pool lying above the Turner Valley Sole Fault as described by W. B. Gallup, W. D. MacKenzie, T. A. Link and others in the Bulletin of the American Association of Petroleum Geologists, Volumes 35, 24 and 18 respectively and as further delineated by the wells drilled into the Rundle group in the Turner Valley Field before July 1, 1971, and including any part of the Rundle group that is, or may be found to be, in reservoir communication with the part of the Pool so described, and within lands hereinafter described are consolidated, merged and otherwise combined in a unit operation in accordance with The Turner Valley Unit Operations Act and subject to the terms and conditions herein contained."

"(1.5) If a well is drilled into the Rundle group in the Turner Valley Field, the Board shall decide whether or not it is completed in the unit."

Further, the opening lines of the clause following that referred to above will be changed to read: "The unit is that portion of the part of the Pool described in clause 1, subclause (1) [or clause 2, subclause (1) in Order No. TVU 7] vertically beneath the lands described as follows:".

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
September 8, 1971

ENERGY RESOURCES CONSERVATION BOARD

DECISION 71-15
Application No. 5561

GAS PROCESSING
WHITECOURT FIELD AND BLUERIDGE FIELD

THE APPLICATION AND HEARING

Pacific Petroleums Ltd. applied under section 38, clause (b) of The Oil and Gas Conservation Act for amendment of the present approval to provide for an increase in the maximum permitted sulphur dioxide emission rate at the Whitecourt Gas Processing Plant, located in Legal Subdivision 12, Section 26, Township 59, Range 11, West of the 5th Meridian. The higher emission limit is applied for due to an increase in the hydrogen sulphide concentration of the raw gas delivered to the plant from 0.15 to 0.30 mole per cent. The maximum permitted sulphur dioxide emission rate would increase from 5.6 long tons per day to 11.3 long tons per day. A new acid gas flare stack, 300 feet in height, would be installed to accommodate the higher emission rate.

Submissions in opposition to the application were filed by Mr. Alex Watson, Mr. F. A. Watson and Mr. E. J. Watson, all residents in the vicinity of the plant. The submission by Mr. F. A. Watson was not presented at the hearing due to Mr. Watson being unable to attend. Mr. E. Juengling, an observer at the hearing, also spoke in opposition to the application.

The application was heard at the Provincial Building Court Room in Mayerthorpe, Alberta, on August 12, 1971, by Board Members, D. R. Craig, P. Eng. and V. Millard.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Pacific Petroleums Ltd.	G. C. Whitaker, P. Eng. A. Phillips	Pacific
Alex Watson	Alex Watson	
E. J. Watson	E. J. Watson	
E. Juengling	E. Juengling	
Department of the Environment	P. M. Ullman, P. Eng. R. M. Stetson	Department

	Represented by	Abbreviation Used in Report
Board Staff	R. B. Dunbar, P. Eng. S. Brown	

PROVISIONS OF PRESENT APPROVAL

Final Air Pollution Approval No. 1094-P-833, issued by the Provincial Board of Health on November 12, 1969, and Approval No. 1171, issued by the Oil and Gas Conservation Board on May 15, 1969, permit the Whitecourt plant to be operated up to a maximum inlet capacity of 50 million cubic feet per day of raw gas containing not more than 200 pound moles of hydrogen sulphide. The approvals require that the hydrogen sulphide removed from the raw gas be flared through a 175-foot flare stack at a sulphur dioxide emission rate not exceeding 5.6 long tons per day and that not less than 19,100 cubic feet per hour of fuel gas be added to the acid gas prior to flaring.

SUBMISSION OF APPLICANT

Pacific's application for a higher sulphur dioxide limit was necessitated by an increase in the hydrogen sulphide concentration of the gas delivered to the plant. Higher concentrations were first observed by Pacific in September, 1970. Since that time the hydrogen sulphide concentration has stabilized slightly below 0.30 mole per cent, and Pacific was of the opinion that it would not increase beyond the present level. Pacific expressed the belief that the increase in hydrogen sulphide concentration occurred after the wells and gathering system equipment became saturated with hydrogen sulphide so that fluids of true reservoir composition began arriving at the plant.

Pacific proposed to continue removing the hydrogen sulphide and carbon dioxide from the raw gas delivered to the plant and dispose of this gas through a new acid gas flare stack 300 feet in height. Sufficient fuel gas would be added to the flared gases to ensure complete combustion of the hydrogen sulphide. Pacific stated the stack height was designed using accepted calculation procedures to ensure that the calculated maximum half-hour average concentration of sulphur dioxide at ground level would not exceed 0.2 parts per million.

Pacific stated it had investigated the possibility of installing a conventional Claus process to recover sulphur and thereby reduce the sulphur dioxide emission. The capital cost for such facilities would be approximately $300,000 to $400,000 and would far exceed the total revenue to be derived from the sale of the sulphur product. In addition the high concentration of carbon dioxide in the plant's acid gas stream would make recovery of sulphur using the Claus process difficult and the recovery efficiency could not be expected to be much over 50 per cent. Pacific concluded that sulphur recovery would be technically difficult, uneconomic, and would reduce sulphur dioxide emission by only some 50 per cent.

Pacific stated it also considered injecting the acid gas to an underground formation but concluded that it would be impractical since the capital cost of the necessary compressors would be approximately $800,000 and the annual operating cost would be approximately $100,000, such costs being completely disproportionate to the worth of the plant operation. In addition there could be metallurgical and safety problems with such a facility. Pacific stated that other sulphur recovery processes now being developed in the industry were not considered because of their high capital costs and, as yet, unproven performance.

In view of the disadvantages of the alternatives studied the applicant submitted that the proposed flaring of the acid gas would be the only practical method of disposing of the hydrogen sulphide.

Pacific stated that the gases would be elevated beyond the 300-foot level of the top of the stack due to the upward velocity of the gases leaving the stack and the bouyancy resulting from the heat of the flame. Calculations performed by the applicant indicate that the gas would disperse before reaching the ground to the extent that sulphur dioxide concentrations at ground level would not exceed the Provincial standard of 0.2 parts per million. At these concentrations Pacific stated it should not be possible to smell or taste the sulphur dioxide.

In support of its application Pacific stated that it operated a continuous sulphur dioxide monitor on the property of Mr. Alex Watson from July 28, 1971, to August 6, 1971. During this period sulphur dioxide was detected on only three occasions, with each reading 0.02 parts per million or less.

Pacific stated that it would be prepared to install additional exposure cylinders in the critical areas in the plant vicinity to monitor sulphation levels. Additional monitoring by continuously measuring and recording instruments was not proposed due to the high cost of the monitoring equipment and the necessity of having electric power at the monitoring locations.

The applicant stated that plant upsets did not occur frequently. During upsets the entire raw gas (maximum of 0.30 per cent hydrogen sulphide) stream could be flared through the 69-foot emergency flare stack. Pacific stated this should not cause high ground level sulphur dioxide concentrations due to the low hydrogen sulphide concentration of the raw gas and the high ratio of hydrocarbon to acid gases that would be burned at the flare.

Pacific expressed the opinion that odours would not originate from the well sites. Pacific stated that the field heaters were fueled with raw sour gas and for the same reason as existed during emergency flaring, the quantities of hydrogen sulphide burned should not cause detectable odours. Pacific also stated that emissions did not occur from the well sites except during testing which occurs approximately once per year.

SUBMISSION OF ALEX WATSON

Mr. Alex Watson lives approximately 4½ miles south-east of the plant in the North-west quarter of Section 8, Township 59, Range 10, West of the 5th Meridian. Mr. Watson objected to granting the application claiming that:

1. the plant was now causing periodic occurrences of strong sulphur dioxide fumes at his home,

2. since his home is at a higher elevation than the top of the proposed 300-foot stack, it could consequently be subjected to direct contact with high sulphur dioxide concentrations,

3. on the basis of a statement alleged to be made by the Deputy Minister of Health in January, the sulphur dioxide content of the air in Alberta was reaching a dangerous level,

4. recent occurrences of mysterious coughing by his cattle, might be attributed to sulphur dioxide from the Pacific plant,

5. the flaring of the sulphur is a waste of a resource that could be conserved,

6. the cumulative effects of total emission in the Province is deleterious,

7. the effects of the sulphur dioxide emissions on the plants and animals in the plant vicinity has not been established.

Mr. Watson stated that when there was a strong north-west wind, sulphur dioxide fumes at his house were intolerable. This condition usually occurred between 5:00 a.m. and 9:00 a.m. on warm overcast days.

SUBMISSION OF E. J. WATSON

Mr. E. J. Watson lives approximately six miles east of the plant in the town of Blue Ridge. He stated he had detected sulphur dioxide odours in the town, usually between 8:00 a.m. and 9:00 a.m., during light west or north-west winds, on overcast high humidity days.

Mr. Watson expressed concern that the sulphur dioxide emission would affect all areas surrounding the plant which are higher in elevation than the top of the proposed 300-foot stack. He also expressed concern about the validity of the formula used to determine the required stack height.

SUBMISSION OF E. JUENGLING

Mr. Juengling lives approximately 4½ miles south-west of the plant in the South-west quarter of Section 7, Township 59, Range 10, West of the 5th Meridian. He stated that he often detected odours in the morning but believed they could come from either the plant or the wells. Mr. Juengling cited a specific instance when he detected "rotten-egg" type odours from a well in Section 6, Township 59, Range 10, West of the 5th Meridian approximately six months ago. He stated that the flare at the well was burning at the time. Mr. Juengling stated that no objectionable conditions had existed for approximately the last six months.

Mr. Juengling expressed concern that an increased in emissions from the plant could adversely affect his health.

SUBMISSION OF THE DEPARTMENT

Although the Department did not file an intervention to the application, P. M. Ullman testified on its behalf regarding the ambient air quality standards, the calculation methods used to design the stack, and air pollution levels in the plant vicinity and the Province in general.

The Department stated that the 0.2 parts per million sulphur dioxide ground level concentration standard used in the Province was established by the Provincial Board of Health. At this concentration there has been no proven evidence of any plant or animal damage occurring with continuous exposure. The Department pointed out that the standard is much stricter than the industrial exposure standard of 5 parts per million in which industrial workers can work for 40 hours a week.

Regarding the calculation of ground level sulphur dioxide concentrations, the Department stated the calculation method used by Pacific is that recommended by the Department of the Environment. The Department stated that observed ground level sulphur dioxide concentrations would be lower than calculated concentrations most of the time but that under extremely adverse meteorological conditions, which occur less than 5 per cent of the time, higher concentrations could occur. In the opinion of the Department the 300-foot stack proposed by the applicant would be sufficient to maintain the sulphur dioxide concentrations at safe levels.

The Department stated it would install a sulphur dioxide monitoring trailer in the vicinity of the plant and would investigate the various odour complaints. It also stated it believed the Department of Lands and Forests would be willing to do a tree damage study if it were asked to do so.

Mr. Ullman could not comment on the statement attributed to the Deputy Minister of Health by Mr. Alex Watson but stated that observations made to date by the Department in the plant vicinity do not indicate unacceptable sulphur dioxide concentrations.

VIEWS OF BOARD

The Board is of the opinion that it would be neither technically nor economically feasible to recover sulphur at the Whitecourt plant. The Board also believes that because of economic and safety considerations it would not be desirable to inject the acid gas. It believes that disposal of the hydrogen sulphide from a properly designed and operated flare stack is acceptable in this case.

The Board appreciates the concern of the interveners but accepts the view of the Department of the Environment that sulphur dioxide concentrations that could cause a hazard to the health of plant, animal or human life would not occur at the proposed emission rates.

The Board is satisfied that the proposed 300-foot stack height will be sufficient to safely dispose of the maximum proposed emission of sulphur dioxide. The Board has calculated maximum sulphur dioxide concentrations that could occur at ground level under adverse conditions and found that the calculated maximum concentration does not exceed the 0.2 parts per million standard. The Board recognizes that under extreme conditions higher concentrations could occur but this would happen infrequently and would not endanger the environment.

While the monitoring results referred to by Pacific and the Department of the Environment indicate that sulphur dioxide concentrations exceeding the Provincial standard have not been detected in the past, the Board believes that, in view of the claims of nuisance odours and detectable levels of sulphur dioxide, Pacific's network of exposure cylinder stations should be expanded from four to eight by placing four additional stations in sensitive high elevation regions. The readings from these stations and the odour investigation by the Department of the Environment would provide evidence should the stack design be inadequate for the area.

The Board is of the opinion that some of the odours detected by the interveners could have resulted from nearby gas wells or flow line heaters. The Board's staff will make further investigations to ensure that field operations are satisfactory.

DECISION

The Board will grant the application by Pacific for an increase in the maximum sulphur dioxide emission rate from the Whitecourt gas plant. The Board will limit the emissions of sulphur dioxide to a maximum of 11.3 long tons per day from the proposed 300-foot flare stack and will require additional monitoring devices as discussed above. The amendment of approval is being issued concurrently with this decision.

Board field staff will co-operate with the Department of the Environment in its investigation of odour complaints and atmospheric pollutant concentrations in the plant vicinity and will inform the interveners at the hearing of the outcome of the study.

ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard
Vice Chairman

DATED at Calgary, Alberta
September 17 , 1971

ENERGY RESOURCES CONSERVATION BOARD

Decision 71 - 16
Application No. 5813

POOLING
LEDUC-WOODBEND AREA

INTRODUCTION

(1) Application and Hearing

Spruce Oils Ltd. applied under section 82 of The Oil and Gas Conservation Act for an order that all tracts within the drilling spacing unit consisting of the South half of Section 15, Township 50, Range 27, West of the 4th Meridian, be operated as a unit to permit the drilling for and the production of oil and gas from all formations down to and including the Leduc Formation. At the hearing the application was amended to apply only to the South-west quarter of said Section 15.

The application was heard by the Energy Resources Conservation Board on September 9, 1971, with V. Millard and D. R. Craig, P. Eng. sitting.

(2) Appearances

Spruce Oils Ltd. was represented at the hearing by its president, M. M. Newell. Of the Board's staff, R. D. Florence and N. A. Macleod, Q. C. appeared.

(3) Provisions of the Act

Section 80, clause (b) of The Oil and Gas Conservation Act defines "tract" as meaning "an area within a drilling spacing unit or pool, as the case may be, within which an owner has the right or an interest in the right to drill for or produce oil or gas". Section 82, subsection (1) says, "The owner of a tract within a drilling spacing unit may apply to the Board for an order that all tracts within the drilling spacing unit be operated as a unit to permit the drilling for or the production of oil or gas from the drilling spacing unit". Section 82, subsection (4) lists the matters for which such an order shall provide and clauses (c) and (d) are relevant; clause (c) reading "for the allocation to each

tract of its share of the production of oil or gas from the drilling spacing unit, which allocation shall be on an acreage basis unless it can be shown to the Board that such basis is inequitable" and clause (d) refers to the payment by the owner of a tract of a share of the cost of drilling the well and the cost of operating and abandoning the well.

SUBMISSION AND VIEWS OF APPLICANT

The application showed that the title to the oil and gas rights throughout the South half of Section 15 was uniform, but was divided among several persons each of whom held a fractional undivided interest. Spruce Oils Ltd. had obtained oil and gas leases from all of the owners except one who held an undivided four per cent interest.

At the hearing Mr. Newell stated that he recognized that the drilling spacing unit was not divided into tracts of different areas. He said the applicant and its associates would be reluctant to drill without the right to charge a four per cent share of the total costs to the owner that had not leased his rights, but that with ninety-six per cent under lease they would probably be prepared to go ahead. He argued that there were separate ownerships within the drilling spacing unit and that, therefore, Spruce Oils Ltd. was entitled to apply for a pooling order. He stated that the application had been discussed with the applicant's lawyer and he understood from that discussion that the application was well founded.

VIEWS OF THE BOARD

The Board believes that the applicant has failed to show that its application is within the terms of section 82. The drilling spacing unit to which the application applies is not divided into tracts as defined in the Act. Further, Spruce Oils Ltd., as lessee of an undivided fractional interest in all of the oil and gas rights within the drilling spacing unit, would, on a suitable application, be granted a well license, and therefore, the order applied for is not necessary "to permit the drilling for or the production of oil or gas from the drilling spacing unit".

DECISION

The Board dismisses the application.

ENERGY RESOURCES CONSERVATION BOARD

D R Craig

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
September 22, 1971

ENERGY RESOURCES CONSERVATION BOARD

Decision 71-17
Application No. 5817

GAS PROCESSING
RICINUS WEST FIELD

THE APPLICATION AND HEARING

Aquitaine Company of Canada Ltd. applied pursuant to section 38, clause (b) of The Oil and Gas Conservation Act for approval of an expansion of its gas processing scheme in the Ricinus West Field. The plant, located approximately 25 miles south-west of Rocky Mountain House, Alberta, in the South half of Section 2, Township 37, Range 10, West of the 5th Meridian, would be expanded to process 382 million cubic feet per day of raw gas from which 225 million cubic feet of residue gas, 3,510 barrels of pentanes plus and 4,110 long tons of sulphur would be recovered. The present plant, authorized under Approval No. 1380, which is still under construction, was designed to process 220 million cubic feet per day of raw gas from which 150 million cubic feet of residue gas, 3,000 barrels of pentanes plus and 1,992 long tons of sulphur will be recovered. The expanded plant would recover 96 per cent of the sulphur contained in the raw gas delivered to it during the period commencing with start-up of the expanded plant in late 1972 until December 31, 1973 and 98 per cent after December 31, 1973. The sulphur not recovered would be emitted to the atmosphere through the existing 300-foot incinerator stack at a maximum rate of 336 long tons per day of sulphur dioxide during the period commencing with start-up of the expanded plant in late 1972 until December 31, 1973, after which the maximum rate would be decreased to 168 long tons per day of sulphur dioxide. The maximum sulphur dioxide emission rate presently permitted by Approval No. 1380 is 82 long tons per day.

Submissions in opposition to the application were filed by the Canadian Institute of Forestry and the Alberta Fish and Game Association. The Department of the Environment of the Province of Alberta appeared at the hearing to present comments regarding the Provincial Ambient Air Quality Standards. The application was heard on August 17, 1971 by Board members G. W. Govier, P. Eng. and D. R. Craig, P. Eng.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Aquitaine Company of Canada Ltd.	L. C. Cameron, P.Eng. J. E. Martin, P.Eng. E. A. Pantella, P.Eng.	Aquitaine
Canadian Institute of Forestry	M. Sauza	Institute
Alberta Fish and Game Association	H. Lembicz	Association
Department of the Environment	P. M. Ullman, P.Eng.	Department
Board Staff	L. A. Mazurek, P.Eng. R. B. Dunbar, P.Eng. R. J. Reimond	

DEFINITION OF ISSUES INVOLVED

The Board considers the following to be the main issues:

(a) conservation features,

(b) sulphur dioxide concentration standard,

(c) pollution control features,

(d) possible mercury contamination of the surrounding environment.

CONSERVATION FEATURES

(1) Views of Aquitaine

Aquitaine stated that the Stage II sulphur recovery section (the expansion applied for) would consist of two 2-stage Claus-type plants plus a Sulfreen tail gas unit, which together would recover 98 per cent of the sulphur in the plant feed gas. This section would be essentially identical to that of the Stage I plant, which is still under construction but expected to commence operation in late 1971. Unrecovered sulphur would be incinerated to sulphur dioxide and exhausted to the atmosphere through a 300-foot stack common with the Stage I facilities.

Aquitaine has applied for approval to operate the expanded plant at a sulphur recovery of 96 per cent for the period beginning with start-up of Stage II until December 31, 1973. This period would be approximately 12 months. Thereafter sulphur recovery would be a minimum of 98 per cent. Aquitaine stated that although it would be possible to achieve a higher initial recovery than 96 per cent it would prefer the one year delay to allow time to evaluate fully advances in tail gas sulphur recovery technology so that they could be incorporated in its installation.

Aquitaine stated that it is hopeful that the Sulfreen process can be improved to yield recoveries in excess of 98 per cent. It may be possible to incorporate these improvements into the Stage II plant and eventually convert the Stage I plant to a higher efficiency unit.

Aquitaine stated it is confident that 94 per cent recovery can be maintained with the Stage II Claus plant and that 98 per cent can be maintained with the Stage I sulphur recovery plant before start-up of the Stage II Sulfreen Unit. The Stage II Claus plant would contain new catalyst and would be equipped with an "optimizer" control system to maitain a high recovery level. Experience with the Sulfreen unit in Lacq, France, after one year of operation, has indicated that a 98 per cent recovery level can be maintained. In addition, at the time of the Stage II Claus plant start-up the Stage I Sulfreen plant would have been on stream in excess of one-half year and major start-up difficulties with the Stage I plant would be over.

Aquitaine did not propose to recover propane and butanes products due to the relative dryness of the raw gas stream. Essentially all of the pentanes plus contained in the gas delivered to the plant would be recovered. Hydrocarbons not recovered as part of the pentanes plus product would remain in the residue gas stream.

Aquitaine stated that there would be no flaring of hydrocarbon liquids or vapours during normal operations and essentially all hydrocarbon liquids and vapours would be conserved. Aquitaine requested that the limit for flaring of gaseous hydrocarbons and other gases be one per cent of the total volume delivered to the plant during the period from November 1, 1971 to December 31, 1972 and one-half of one per cent of the total volume delivered to the plant in each year thereafter. The one per cent limit was necessitated because two plant start-ups would take place during that period.

Aquitaine stated that any liquid hydrocarbons entering the flare system would be caught in a liquid separator at the base of the flare stack and would be drained manually and recycled to the plant.

(2) Views of the Institute

The Institute stated that it is not confident that plant operating efficiency could be maintained to recover 96 per cent of the sulphur during the start-up or 98 per cent thereafter. It did not express other specific views on the conservation features of the scheme except for its concern that the recovery should be higher to reduce the emission of unrecovered sulphur, as sulphur dioxide, to the atmosphere.

(3) Views of the Association

The Association did not express any specific views on the proposed conservation levels other than its concern that the sulphur recovery should be higher to minimize the emission of sulphur dioxide to the atmosphere.

(4) Views of the Department

The Department did not express a view on the proposed conservation levels.

(5) Views of the Board

The Board is of the opinion that the proposed sulphur recovery levels are satisfactory provided the unrecovered sulphur is disposed of in an acceptable manner. It believes that operation for a one-year period at the lower 96 per cent recovery level would be acceptable since active development towards improving sulphur recovery technology would be pursued by the applicant. The Board is of the opinion that 94 per cent is a reasonable recovery for a well-equipped two-stage Claus plant and accepts the applicant's view that 98 per cent recovery can be maintained with a two-stage Claus plant followed by a Sulfreen unit. The Board recognizes that recoveries lower than the proposed levels could occur during the plant start-up period or during plant upsets and is of the opinion that if this occurs the plant operator should reduce plant through-put to maintain sulphur dioxide emission rates below an acceptable maximum. This matter is further discussed later in this decision.

The Board is also generally satisfied with the measures proposed for the conservation of hydrocarbons. The Board agrees that some additional gas flaring could be necessary during the plant start-up periods and is of the opinion that a one per cent flaring limitation between November 1, 1971 and December 31, 1972 and a one-half of one per cent flaring limitation in each year thereafter would be reasonable.

SULPHUR DIOXIDE CONCENTRATION STANDARD

(1) Views of Aquitaine

Aquitaine stated it would comply with standards established by the Board and the Department of the Environment but did not express a view on the sulphur dioxide concentration standard.

(2) Views of the Institute

The Institute expressed concern that the standard of 0.3 parts per million maximum one-half hour average concentration of sulphur dioxide at tree top level applied in the plant vicinity is too high. It stated that damage to vegetation can occur at sulphur dioxide concentrations below 0.3 parts per million. The Institute made reference to a case where white pine was damaged when exposed to sulphur dioxide concentrations up to 0.25 parts per million. It also quoted a reference which stated that exposure to sulphur dioxide at levels less than 0.1 parts per million for four hours induced acute injury to new needles of white pine. It stated that while there appears to be no published tolerance levels for lodgepole pine, or for other major species in the vicinity of the applicant's site, it is of the opinion that sulphur dioxide concentrations should not be allowed to exceed those levels for which there is documented evidence of damage to forest vegetation.

In response to a statement by the Department, the Institute stated that in the cases referred to it believed that sulphur dioxide was the only contaminant present and was the cause of the tree damage referred to.

The Institute also expressed concern that agricultural land is located from eight to ten miles from the plant and that the standard of 0.2 parts per million maximum one-half hour average concentration of sulphur dioxide at ground level should be applied in that area.

The Institute also stated that because sulphur arising from the processing of natural gas in Alberta has been detected in British Columbia and Saskatchewan the application should be subject to regulation by some Federal agency under The Clean Air Act of the Government of Canada.

(3) Views of the Association

The Association did not express a view on the sulphur dioxide concentration standard.

(4) Views of the Department

The Department stated that the standards were established by the Government of Alberta at levels recommended to the Minister of Health by a special committee established to investigate air pollution standards. The standards were established at concentrations at and below which there is no documented evidence of the occurrence of damage to plant, animal or human life. The Department stated that the standards are based on sulphur dioxide concentrations averaged over a one-half hour period and would correspond to lower concentrations averaged over longer periods of time. The Department stated that in the cases referred to by the Institute the damage occurred due to longer than one-half hour exposures and could have resulted due to the presence of other contaminants in the air.

The Department stated that the applicant should be required to comply with the standard of 0.3 parts per million at tree top level in forested areas and the standard of 0.2 parts per million at ground level in the agricultural areas.

The Department also stated that in its view The Federal Clean Air Act should not be of concern in the consideration of the application.

(5) Views of the Board

The Board appreciates the view of the Institute but accepts the standards of the Department of the Environment. The Board notes that the applicant has consulted the Department of Lands and Forests of the Government of Alberta and the Department of Fisheries and Forestry of the Government of Canada regarding proposed studies to assess the effect of the emissions on the plant and animal life in the plant vicinity and expects that the present standards would be modified if the proposed studies or any directly relevant observations indicated any adverse effect of the emissions on the environment.

The Board will require that Aquitaine comply with the standards established for both the agricultural and forested areas in the plant vicinity.

POLLUTION CONTROL FEATURES

(1) Views of Aquitaine

Aquitaine stated that its calculations for both the 336 and the 168 long tons per day sulphur dioxide emission rates indicate that the existing 300-foot stack would be adequate to maintain the concentration of sulphur dioxide at tree top level below the standard of 0.3 parts per million, averaged over a

one-half hour period, up to an elevation of 5300 feet above sea level and for all wind speeds up to 15 miles per hour. Aquitaine stated that calculated sulphur dioxide concentrations exceed 0.3 parts per million on Baseline Mountain west of the plant at elevations above 5300 feet for wind speeds in excess of 15 miles per hour and for lower wind speeds. Meteorological data collected in the area, however, indicates that winds exceeding 15 miles per hour blow in the direction of Baseline Mountain less than one per cent of the time.

Aquitaine stated that at the 336 long ton per day sulphur dioxide emission rate the stack exit temperature would be maintained above 1100 degrees Fahrenheit and the stack gas volume rate of flow would be a minimum of 9206 cubic feet per second to ensure that the sulphur dioxide concentration standard would not be exceeded. The high stack gas volume rate of flow would be attained using an air blower on the stack and by burning additional fuel in the incinerator.

The applicant stated that it used accepted calculation methods to determine the maximum sulphur dioxide concentrations. It stated that these methods do not completely evaluate the effect of undulating topography and for this reason Aquitaine had been working with a computer design group involved in developing a new air pollution model which does account for undulations in the topography. Aquitaine stated that calculations made using this model indicated lower sulphur dioxide concentrations than those predicted by the normal formula.

The applicant stated that it had evaluated the combined effect of emissions from the proposed plant and the Gulf Oil Canada Limited Strachan plant, approximately eight miles north-east, on the ground level sulphur dioxide concentrations in the area and is of the opinion that there would be no significant additive effect due to the two plants.

In view of the fact that concentrations exceeding the standard were calculated for wind speeds exceeding 15 miles per hour and for elevations exceeding 5300 feet, Aquitaine stated that it would be prepared to operate mobile air pollution monitors in the area, as may be prescribed by the Board, to more closely monitor ground level sulphur dioxide concentrations. It also stated that it would install telemetering equipment to transmit measured concentrations to the plant continuously. In the event that the measured ground level sulphur dioxide concentration exceeded 0.3 parts per million the plant throughput would be reduced immediately to maintain concentrations within the prescribed limit.

Aquitaine stated that it presently had one monitoring station in operation and that a second would be operational by the end of August. It also stated that several exposure cylinder stations were being maintained. Aquitaine said it would be prepared to expand the monitoring network if required by either the Board or the Department of the Environment.

Respecting the effects of the plant on local plant and animal life the applicant stated it had been in contact with the Department of Lands and Forests of the Government of Alberta and the Department of Fisheries and Forestry of the Government of Canada regarding two studies proposed for the plant vicinity. It proposed an air photographic infra-red study to assess vegetation damage and a biological survey in which plant and animal samples would be examined to assess the effect of the plant on the environment.

Aquitaine stated that a flare stack, 150 feet in height, would be installed at the plant to provide for emergency flaring from either the Stage I or the Stage II facility. Sufficient fuel gas would be automatically added to the flare to maintain complete combustion and provide the necessary stack exit temperature. Aquitaine stated that flaring would be minimal, even during an emergency, as the field supervisory control system would be used for the rapid shut-in of all wells. It also stated that flaring during the start-up period would be held to a minimum through the use of an elaborate start-up procedure which would involve placing all pollution control units on stream before the start-up of the rest of the plant.

Aquitaine stated that it did not anticipate significant emission of black smoke due to the dryness of the gas and accordingly did not plan to install any special smoke abatement equipment on the flare stack.

Aquitaine stated that it had applied to the Department of the Environment for approval of the waste water treating and disposal facilities for that portion of the waste water that would be disposed of to Baseline Creek. Untreatable process waste water and produced salt water would be injected to an underground formation for which separate approval of the Energy Resources Conservation Board will be required.

In reply to questions by the Association, Aquitaine stated that it had applied to the Water Resources Division for approval of its proposed fresh water supply wells to be located approximately four miles south-east of the plant. Three wells would be drilled to a depth of 150 to 200 feet. Any two of the wells would have sufficient capacity to supply the entire needs of the plant.

(2) Views of the Institute

The Institute expressed concern that the proposed stack emissions would cause sulphur dioxide concentrations exceeding the Provincial standard. It stated that it was concerned that the application indicated that the standard would be met at wind speeds of 15 miles per hour but did not indicate what concentrations could result at lower wind speeds or on calm days. It also expressed concern that proper consideration was not given to the effect of undulating topography, which could be expected to result in areas of excessive concentration of effluent gases. The Institute stated that the influence of forest cover on air turbulence and mixing should also be considered as the generally calmer air beneath the tree canopy could lead to concentrations lethal to vegetation. It expressed concern over the combined effect the emissions from the proposed plant and the Gulf Oil Canada Limited Strachan plant would have on sulphur dioxide concentrations. In addition, it stated that under certain meteorological conditions the gases from the stack could remain unsatisfactorily diluted, travel in a plume for many miles, and finally touch the ground at concentrations lethal to vegetation. The Institute also expressed concern that if the total plant inlet stream were flared, the total sulphur dioxide emission rate would be in the order of 8500 long tons per day, and sulphur dioxide concentrations at ground level could be in the order of 10 parts per million.

The Institute stated that in its view clear legal guidelines should be described for individual compensation in the event of damages. It questioned how a citizen of Alberta, if deprived of income or his normal enjoyment of the forests of the region containing the plant, might proceed to obtain compensation for his loss, should such occur.

(3) Views of the Association

The Association expressed concern over the effects the sulphur dioxide could have on the health of plant, animal and human life in the plant vicinity. It expressed the view that the 336 long tons per day rate would weaken the plant and animal life during the first year of operation and that the 168 long tons per day rate thereafter would have a further deleterious effect. It also expressed concern that emission during the start-up period could far exceed the proposed maximum rates.

The Association suggested that the proposed fresh water supply wells might drain the watershed now serving Swan Creek and eventually affect the water supply of Swan Lake.

(4) Views of the Department

The Department did not express a view on the pollution control features of the scheme.

(5) Views of the Board

The Board staff has calculated the sulphur dioxide concentrations that could occur both at tree top level in the forested areas and at ground level in the agricultural area east of the plant. The results of the Board staff calculations are similar to those of the applicant and indicate that:

1. the concentrations of sulphur dioxide at ground level in the agricultural area east of the plant would not exceed the 0.2 parts per million Provincial standard;

2. for wind speeds up to and including 15 miles per hour:

   (a) the sulphur dioxide concentration at tree top level would not exceed the 0.3 parts per million Provincial standard at and below the 5200-foot elevation of the mountains west of the plant,

   (b) the sulphur dioxide concentration at tree top level above the 5200-foot elevation would exceed the 0.3 parts per million Provincial standard.

3. for wind speeds greater than 15 miles per hour and up to 30 miles per hour:

   (a) the sulphur dioxide concentration at tree top level at and below the 4800-foot elevation would not exceed the 0.3 parts per million Provincial standard,

   (b) the sulphur dioxide concentration at tree top level above the 4800-foot elevation would exceed the 0.3 parts per million Provincial standard.

The Board staff has also performed calculations to evaluate the effect of the combined emissions from the proposed plant and the Gulf Oil Canada Limited Strachan plant on sulphur dioxide concentrations in the area and finds that these effects are not significant.

The Board recognizes that under certain meteorological conditions, concentrations of sulphur dioxide higher than those calculated could occur but is of the opinion that the higher concentrations would only occur under severe atmospheric conditions which happen infrequently and that more than 95 per cent of the time observed concentrations would be less than those calculated.

In light of the calculations, which indicate that sulphur dioxide concentrations could exceed the Provincial standard under certain conditions, the Board is of the opinion that the proposed sulphur dioxide emission rates should only be permitted with operation of an adequate sulphur dioxide monitoring network in the plant vicinity to ensure that the sulphur dioxide concentration standard is not exceeded. The Board believes that stations could be located to provide for coverage of the critical areas and that continuous transmission of measured sulphur dioxide concentrations should be provided so that appropriate corrective action could be taken at the plant as soon as critical concentrations were observed. Since it is not practical to provide complete coverage, the Board believes that it would be necessary for the plant to initiate corrective action at some concentration less than the standard since it is possible that a concentration exceeding the standard could exist within the area of interest and not be detected by one of the monitors. The time lag which exists between the instant of emission and the time the pollutant reaches a monitoring station also makes it desirable to initiate corrective action at some detected concentration less than the standard, to lessen the possibility of the standard being exceeded before corrective action is effective. On this basis the Board believes that it would be necessary for the plant to initiate some form of corrective action any time the measured concentration exceeded 0.2 parts per million at ground level, averaged over a 15-minute period. Since the critical area was determined to be Baseline Mountain and the other ridges west of the plant, the Board is of the opinion that a minimum of four continuously operating monitoring stations should be required in this area; one at the Baseline Mountain lookout tower, and three at approximately the tree line of the ridges west of the plant, at exact locations determined in consultation with the Department of the Environment before start-up of the Stage II facilities.

The Board is also of the opinion that additional exposure cylinder stations should be required in the area west of the plant to provide additional monitoring in this critical area. Ten additional stations, five at the 5300-foot elevation and five at higher elevations, should therefore be installed prior to Stage II start-up.

Since the stack gas flow rate is a critical stack height design parameter, the Board is of the opinion that this flow rate should be maintained above a minimum proportional to the sulphur dioxide emission rate. Calculations indicate that up to December 31, 1973 the stack gas flow rate should be a minimum of approximately 9200 cubic feet per second at the maximum sulphur dioxide emission rate of 336 long tons per day and after December 31, 1973 the stack gas flow rate should be a minimum of approximately 7000 cubic feet per second at the maximum sulphur dioxide emission rate of 168 long tons per day.

The Board notes that an elaborate control system is proposed to minimize flaring in the event of an emergency. Each well site would be equipped with a local control system to provide automatic shut-in of the well in the event of high flow-line pressure, low flow-line pressure or fire. In addition, a well shut-down may be initiated from the plant control room through the supervisory control system. The Board is of the opinion that with these facilities flaring would be minimal and could be rapidly brought under control in the event of an emergency.

In the event that flaring did occur, the Board notes that two separate emergency flare systems, each terminating at a 150-foot flare stack, would be utilized. The stack has been designed to handle the entire raw gas flow to the plant. Aquitaine stated that provision has been made to automatically add sufficient fuel gas to the flare when necessary to maintain ground level sulphur dioxide concentrations within the Provincial standards during sour gas flaring. The Board staff has checked the flare stack design and is of the opinion that the proposed system is satisfactory. Board staff calculations confirm that sulphur dioxide concentrations could be maintained within the Provincial standards during emergency flaring with the addition of sufficient fuel gas.

The Board notes that Aquitaine has applied to the Department of the Environment for approval of its proposed waste water disposal facilities and to the Water Resources Division for approval of its proposed fresh water supply wells.

The Board is not prepared to present a detailed view on the Institute's suggestion that legal guidelines be described for individual compensation in the event of damages. The Board believes that should damage occur compensation could be ascertained in the normal way, i.e. by agreement among the parties or through the courts.

THE POSSIBILITY OF MERCURY CONTAMINATION

(1) Views of the Association

The Association quoted statements from published papers that mercury can enter the biosphere by the burning of oils, gases or other fossil fuels which contain trace quantities of mercury. The mercury could then enter lakes and streams and accumulate in fish inhabiting these waterways, eventually reaching dangerous levels. The Association stated that mercury concentrations above normally acceptable levels have been detected in fish in the Red Deer and North Saskatchewan Rivers and speculated that gas processing plants in the Province could be the mercury source.

Although the Association did not have specific evidence of the presence of mercury in Ricinus West reservoir fluids, it stated that the possibility of mercury being contained therein and being emitted to the atmosphere through the plant stack should be investigated.

(2) Views of Aquitaine

Aquitaine stated that it had not detected mercury in any of its reservoir fluid samples although it had not specifically looked for trace concentrations of this element. Aquitaine stated that if mercury were present in the fluids delivered to the plant it could only escape to the surroundings through the incinerator stack as all other plant fluids are contained and not permitted to escape.

(3) Views of the Institute

The Institute did not state a view on the matter of possible mercury contamination.

(4) Views of the Department

The Department had no comments regarding the matter of possible mercury contamination.

(5) Views of the Board

At the time of the hearing the Board had no knowledge of the presence of mercury in any Alberta reservoir fluids, but following the hearing decided that the matter should be investigated further. The Board has initiated an investigation of the problem. Arrangements have been made to take several samples of gas and condensate from the Ricinus West, Strachan and other reservoirs in the Province to be analyzed specifically for trace quantities of mercury. Initial results of this sampling

indicate a maximum detected mercury concentration of the gases sampled of 2.1 grams of mercury per billion standard cubic feet of gas. Assuming the gas contains this maximum concentration the total mercury entering the proposed plant at the maximum raw gas inlet rate would be approximately 1.3 grams per day, or just over one pound per year. In the opinion of the Board, these preliminary results indicate that any mercury emission from the plant would be negligibly small and would not contaminate the environment. The Board's investigation is continuing.

DECISION

The Board approves the application subject to the condition that Aquitaine install and maintain four monitoring stations for the detection of sulphur dioxide in the plant vicinity at locations to be approved by the Board and the Department of the Environment. The measured sulphur dioxide concentrations are to be transmitted continuously to the plant and Aquitaine will be required to reduce plant through-put whenever the measured concentration exceeds 0.2 parts per million averaged over a 15-minute period, to maintain the concentrations within this limit. The Board will also require that ten additional exposure cylinder stations be installed and results therefrom at locations west of the plant and satisfactory to the Board and the Department of the Environment.

Additional detail concerning the monitoring requirements is contained in Approval No. 1605 being issued concurrently with this decision.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

DATED at Calgary, Alberta
October 18, 1971

ENERGY RESOURCES CONSERVATION BOARD

Decision 71-18
Application No. 6013

GAS PROCESSING NEVIS FIELD

THE APPLICATION AND HEARING

Chevron Standard Limited applied on behalf of itself and other owners of the Nevis Operators' Committee Gas Processing Plant (hereinafter called the "Nevis Plant"), pursuant to section 38, clause (b) of The Oil and Gas Conservation Act, for amendment of Approval No. 1386 to authorize an increase in the plant capacity from 80 million to 100 million cubic feet per day (MMcfd), the installation of an IFP sulphur recovery unit and operation of the plant at rates up to 95 million cubic feet per day pending installation of the IFP unit.

The application was heard at Red Deer on November 24, 1971 by the Board, with D. R. Craig, P. Eng. and V. Millard sitting.

APPEARANCES

The following appeared at the hearing:

	Abbreviation Used in Report	Represented by	Witnesses
Chevron Standard	Chevron	D. P. McLaws, Q.C. (of McLaws & Company)	L. C. Zerr, P.Eng. W. M. Newhouse, P.Eng.
F. Solterman A. R. Ramsay	Interveners	F. M. Saville (of Brownlee, Fryett & Company)	F. Solterman A. R. Ramsay
Department of the Environment	Department	P. M. Ullman, P.Eng.	P. M. Ullman, P.Eng.
Board Staff		N. A. Macleod, Q.C. L. E. Hicklin, P.Eng. L. A. Mazurek, P.Eng. R. B. Dunbar, P.Eng.	

SUBMISSION OF APPLICANT

The Nevis Plant is located in the Nevis Field in the South-east quarter of Section 22, Township 39, Range 22, West of the 4th Meridian.

Chevron stated that the application for an increase in maximum production rate from 80 to 100 MMcfd resulted from a recognition of additional gas reserves and an increase in rate of take by the gas purchaser, Trans-Canada Pipe Lines Limited, and that it would not be necessary to alter the current process of the Nevis Plant to accommodate the higher rates. Chevron stated it would not alter the present level of sales gas quality or condensate recovery. Chevron did, however, propose to install IFP (Institut Francais du Petrole) tail gas clean up facilities to recover 50 per cent of the sulphur contained in the tail gases of the existing two Claus sulphur plants. After installation of the IFP facility the design sulphur recovery level of the sulphur plants would be 98.25 per cent. Chevron stated that, after making allowance for catalyst deterioration, possible plant upsets and other abnormal plant operating occurrences, it would be possible to maintain an overall plant recovery of 97.5 per cent.

Chevron stated that calculations indicate that the 0.2 parts per million maximum calculated ground level sulphur dioxide concentration standard would not be exceeded at the maximum proposed throughput with the IFP facilities in operation

For the interim period to July 31, 1972, during which time the IFP facilities would be constructed, Chevron asked permission to operate at raw gas inlet rates up to 95 million cubic feet per day while maintaining a 96.5 per cent sulphur recovery efficiency, which would result in a maximum sulphur dioxide emission rate of 17.8 long tons per day. Calculations by Chevron, using the Pasquill method, indicated that the maximum calculated ground level sulphur dioxide concentration would exceed at the higher emission rate the 0.2 parts per million (ppm) standard to the north of the plant, in the segment bounded by the north-east and north-west directions when the wind speed was equal to or exceeded 12 miles per hour, and to the south of the plant, in the segment bounded by the south and south-west directions when the wind speed was equal to or exceeded 8 miles per hour. Chevron stated that when these adverse wind conditions occurred, the plant raw gas inlet rate would be reduced to 80 million cubic feet per day to reduce the sulphur dioxide emission rate and ensure that the calculated ground level concentration standard would not be exceeded.

Chevron stated that in its opinion there would be no increase in the ground level concentrations of sulphur dioxide as a result of operation at the higher inlet rate for the interim period terminating July 31, 1972. Chevron gave limited evidence that past operation at rates above 80 MMcfd, which were approved by the Board for testing purposes, did not directly result in an increase in ground level sulphur dioxide concentrations. Such increases as did occur were judged by Chevron to be due to plant upsets and not attributable to the effect of higher rates. With regard to the possibility, at the higher rates, of high concentrations due to the overlap of plumes from the two plants in the Nevis Field, Chevron said that it did not investigate this problem.

Chevron testified that when considering sulphur emission control in relation to expansion of its plant from 80 MMcfd to 100 MMcfd raw gas inlet rates, it had two options to meet the current environmental standards set by government. The first and cheapest was a simple increase in incinerator stack height and some adjustment in the stack gas fuel. The second was the installation of the much more expensive IFP tail gas clean up system. Chevron considered the second to be the much preferred solution since it achieved pollution abatement by removal of sulphur rather than by simply increasing the dispersion of it. Chevron pointed out that the installation of the IFP facilities would result in the sulphur recovery efficiency of the plant being significantly higher than the Board's recently published minimum sulphur recovery guideline. However, Chevron contended that it would be difficult to justify the substantial increased expenditure of the IFP process unless the owners could achieve an improved plant income during the installation period. The applicant proposed that the Board permit the owners to operate the plant at increased production rates to July 31, 1972 under carefully controlled conditions. The applicant believed that this proposal would be warranted since long term benefits to both society and the plant owners would result. Also, should pollution abatement standards become more stringent in the future, the plant could be more readily modified to meet them if the IFP system were installed.

SUBMISSION OF INTERVENERS

The interveners own land and reside near the Nevis Plant.

The interveners stated that since the applicant proposes to install an emission control system to reduce sulphur dioxide emissions from the plant it should not be permitted to increase the plant capacity until such time as the emission control system had been installed. The interveners were of the view that the increase in sulphur dioxide emission which would result

due to the increase in plant throughput prior to the installation of the IFP process would affect the interveners and their property in a harmful way. The interveners contended that plant emissions had already affected them and their property and cited past instances of ill effects.

STATEMENT OF DEPARTMENT OF THE ENVIRONMENT

The Department stated that although the Pasquill method can be used to calculate maximum sulphur dioxide concentrations that would occur under most meteorological conditions the results of the calculations should not be interpreted to precisely represent all the effects that unusual weather conditions could have on ground level concentrations in an area. For this reason the Department stated that it did not believe the proposal by Chevron, whereby plant throughput would be reduced when those wind conditions calculated to be critical by the Pasquill method prevailed, would ensure in absolute terms that the standard would not be exceeded occasionally in the plant vicinity.

VIEWS OF THE BOARD

The Board believes that the application to increase the permitted plant throughput from 80 to 100 MMcfd because of change in contractual obligations is reasonable and would be satisfactory from a conservation viewpoint.

With regard to pollution control, the Board is satisfied that the installation of the proposed IFP facilities would significantly reduce the average sulphur dioxide emission rate from the plant, and would thereby reduce the effect the plant emissions would have on the surrounding environment. The proposed minimum overall sulphur recovery of 97.5 per cent is higher than that specified under the Board's guideline for minimum sulphur recovery efficiency. The Board agrees with Chevron that the proposed installation of tail gas clean up facilities is much more desirable than increasing the incinerator stack height and recognizes that this would result in a substantial increase in both capital and operating costs.

Respecting the possible impact on the environment of two sour gas processing plants in the same area, the Board staff investigated whether ground level concentrations of sulphur dioxide in the area would exceed the Provincial standard due to possible overlap of the two exhaust plumes. Their calculations indicate that the overlap would not likely cause the standard to be exceeded. The Board is therefore of the opinion that no serious additive effects would occur.

With respect to the applicant's proposal to operate at higher rates during an interim period, the Board notes that air monitoring results from two surveys conducted by Western Research and Development Limited indicated that the Provincial ambient air quality standard of 0.3 ppm averaged over a one hour period was not exceeded, although peak readings considerably in excess of 0.3 ppm were recorded for short durations. The Board accepts the testimony of Chevron that most of these high concentrations occurred during periods of plant operating difficulties and were not attributable to operation at higher throughputs. It appears to the Board that plant reliability has been improved recently and that the frequency of plant upsets has decreased. As the Board sees it, the pollution complaints by residents probably are related to plant upsets and further attention to and improvement of plant reliability by the applicant is needed.

The Board notes that, with the proposed restrictions during adverse wind conditions, plant operations at an inlet rate of 95 MMcfd would meet the calculated ground level concentration criteria established by the Department of the Environment. The Board accepts the view of the Department that placing operating restrictions on the plant with respect to critical wind conditions determined by Pasquill calculations may not in every instance effectively control ground level sulphur dioxide concentrations. The Board believes that the use of extra ambient air monitoring equipment would provide additional assurance of the control of sulphur dioxide concentrations. In the Board's opinion, the significant long term improvement in pollution abatement obtained by the IFP process as compared to an extension of the incinerator stack must be balanced against the proposed increased sulphur emission rates for the interim period. Accordingly, and subject to certain operating restrictions and the use of extra monitoring equipment, the Board is prepared to allow the interim increased operating rates. If ambient air monitoring were to indicate an unacceptable number of occurrences of sulphur dioxide concentrations in excess of the standard, the Board would reduce forthwith the allowable emission limit to a lower level.

DECISION

The Board will grant the application to increase the plant maximum raw gas inlet rate to 95 million cubic feet per day until July 31, 1972 and to 100 million cubic feet per day thereafter. The Board will require that the sulphur dioxide emission rate does not exceed 17.8 long tons per day until July 31, 1972 or 12.5 long tons per day thereafter. In addition to other normal requirements, the Board will require during the interim period ending July 31, 1972 that a continuously measuring and recording sulphur dioxide monitor be in operation at all times and at various locations to be approved by the Board.

The Board will also require the recovery in the form of elemental sulphur of not less than 96.5 per cent of the sulphur contained in the raw gas delivered to the plant during the interval ending July 31, 1972, and 97.5 per cent of the sulphur contained in the raw gas delivered to the plant thereafter. During the period ending July 31, 1972 the Board will require that the maximum sulphur dioxide emission rate be limited to 12.5 long tons per day under certain critical wind conditions specified in the approval or when the ambient air sulphur dioxide monitor referred to above is out of service. The Board will rescind or modify the approval if the monitored results indicate an unacceptable number or prolonged occurrences of sulphur dioxide concentrations in excess of the standard.

To implement its decision the Board will issue a new approval for the plant at an early date revising and consolidating the present approval.

ENERGY RESOURCES CONSERVATION BOARD

D R Craig

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
December 30, 1971

ENERGY RESOURCES CONSERVATION BOARD

Decision 71-19
Proceeding No. 5915

GAS WELL PRODUCTION ALLOWABLES

HEARING

A hearing was held by the Board for the purpose of hearing representations respecting the need for and the data to be used in establishing maximum daily production rates (Q_{max}) for gas wells in the pools listed in Attachment I.

The hearing was held by the Board in Calgary, Alberta on October 26, 1971, with D. R. Craig, P. Eng. and V. Millard sitting.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Atlantic Richfield Canada Ltd.	S. Vavra, P. Eng. M. N. Kinakin, P. Eng. G. S. Boon, P. Eng.	Atlantic Richfield
Canadian Fina Oil Limited	H. D. Bagley, P. Eng.	Fina
Canadian Industrial Gas & Oil Ltd.	D. R. Jepson, P. Eng. W. R. Brooke, P. Eng.	CIGOL
Canadian Superior Oil Ltd.	M. T. Alexandre, P. Eng.	Canadian Superior
Chevron Standard Limited	J. D. Scott, P. Eng. G. W. Cruickshank, P. Eng. R. A. Filgate, E.I.T. P. V. Malowany, P. Eng.	Chevron
Dome Petroleum Limited	R. H. Johnson, P. Eng.	Dome
Gulf Oil Canada Limited	W. K. Good, P. Eng. D. Thompson, P. Eng.	Gulf
Home Oil Limited	F. R. Erick Mulder, P. Eng.	Home

	Represented by	Abbreviation Used in Report
Hudson's Bay Oil and Gas Company Limited	H. G. Kershaw, E.I.T. S. K. Chakravorty, P. Eng. S. Morgan, P. Eng. M. B. Field	Hudson's Bay
Board Staff	D. G. Pearson, P. Eng. P. M. Stanton, P. Eng. M. E. Mumby	

SUBMISSIONS AND FINDINGS OF THE BOARD

Nine pools were considered for either Q_{max} (daily maximum allowable) restrictions or Good Production Practice Status. No pools were considered with respect to daily average allowables (MPR_G). Each pool is considered below.

Gold Creek Wabamun A Pool

Views of Atlantic Richfield

Atlantic Richfield submitted that the Q_{max} formula is not a valid means of controlling pressure drawdown in a reservoir such as Gold Creek Wabamun A where production occurs below the dew point and where stabilized producing conditions do not occur within a reasonable length of time. It further submitted that the production capability of the four producing wells is approaching the operating economic limit for the plant. Atlantic Richfield therefore asked that the Gold Creek Wabamun A Pool be permitted to be produced at rates consistent with good production practice.

Views of the Board

The Board agrees with Atlantic Richfield that the Q_{max} formula may not be an appropriate method for controlling pressure drawdown to prevent reservoir damage in this pool. The Board notes that over the past two years there have been no significant changes in water production rates for the four producing wells. In view of the problems associated with producing this pool, the Board is prepared to permit production at rates consistent with good production practice but will require Atlantic Richfield to submit, by August 31 of each year, a report discussing the manner in which the pool has been operated during the previous 12-month period, and outlining future plans to obtain maximum gas recovery.

Harmattan-Elkton D-3 A Pool

Views of Canadian Superior

Canadian Superior stated that the gas production rates determined by its coning study are still valid for the majority of wells in the pool. It sought the adoption of Q_{max} rates of 110 per cent of the rates suggested by this study except for three wells, those located in Legal Subdivision 6 of Section 8, Legal Subdivision 10 of Section 9 and Legal Subdivision 11 of Section 16, all in Township 32, Range 4, West of the 5th Meridian, for which it asked alternate rates having regard for performance and producing problems.

Views of the Board

The Board appreciates the problems associated with producing this gas, which contains some 52 per cent hydrogen sulphide and finds the rates suggested by Canadian Superior to be acceptable for six of the wells. The Board is, however, concerned with the excessive water-gas ratios experienced at the wells located in Legal Subdivision 6 of Section 8 and Legal Subdivision 11 of Section 16. The Board, after examining the production history is of the opinion that lower Q_{max} rates are warranted in the interests of minimizing irreversible damage to hydrocarbon recovery and believes that Q_{max} rates of 2.0 MMcfd and 3.0 MMcfd respectively are appropriate for the said two wells.

The Board believes that this pool should be considered at the 1972 Q_{max} hearing to review the results of the updated coning simulation study proposed by Canadian Superior.

Kaybob South Bearverhill Lake A Pool

Views of Chevron and Hudson's Bay

Both Chevron and Hudson's Bay asked that maximum daily gas production rates for the wells in this pool be based on results of their separate coning behaviour model studies. Chevron recommended the adoption of the rates found in its study, while Hudson's Bay asked that no Q_{max} rates be issued for the pool until firm rates could be established from production experience.

Views of the Board

The Board observes that some wells in Unit 1 and Unit 2 are still experiencing water problems and that Hudson's Bay is having difficulty in matching actual performance with that predicted from coning simulation studies. The Board notes that Hudson's

Bay has imposed drawdown factors equal to or greater than 0.95 on its wells and accepts the Q_{max} rates recommended by Hudson's Bay.

For wells in Unit 3, Chevron has generally suggested drawdown factors of 0.90 or greater. However, a drawdown factor of 0.594 was suggested for the well located in Legal Subdivision 5 of Section 23, Township 59, Range 18, West of the 5th Meridian which Chevron interpreted to have limited matrix permeability. The Board believes that production history is required to adequately test the accuracy of the coning model and therefore accepts Q_{max} rates proposed by Chevron with the exception of the rate proposed for the well located in Legal Subdivision 5 of Section 23. The Board believes a drawdown factor of 0.75 is appropriate for this well until experience indicates otherwise.

The Board is generally satisfied that the operators in Kaybob South are continuing their efforts to develop effective criteria for controlling water production. In order that the Board may be kept aware of continuing developments, the pool will be re-examined at the 1972 Q_{max} Hearing.

Lookout Butte Rundle A Pool

Views of Gulf

Gulf submitted that of the ten producing wells in the pool only BA Lookout Butte 11-31-1-28, BA Lookout Butte 4-13-2-29, BA Lookout Butte 4-32-1-28, and Gulf Lookout Butte 13-6-2-28 are producing formation water. It submitted that water production from all wells in the pool is rate sensitive on a short-term basis only, and that long-term water-gas ratio behaviour is related to cumulative withdrawals. Gulf requested that a draw-down factor of 0.75 be assigned to each well. It also asked that maximum daily allowables for the first two days following lengthy shut-in periods be waived, and that no Q_{max} rate be set below 3000 Mcfd.

Views of the Board

The Board agrees in part with Gulf's contention that water production from the wells is rate sensitive on a short-term basis only, and also with its contention that long-term water-ga ratio behaviour is related to cumulative withdrawals. The Boar believes, however, that the pressure gradients which exist aroun each well bore remain a function of producing rate, and therefor that production rates should be controlled in certain wells to prevent harmful water migration in the reservoir. The Board believes that Q_{max} rates can be departed from for the first two

days following lengthy shut-in periods without harmful effects to the reservoir. It accepts Gulf's request that a minimum Q_{max} rate of 3000 Mcfd is necessary to alleviate the hydrate problems which occur at lower producing rates, and accordingly will assign a Q_{max} rate of 3000 Mcfd in those instances where the calculated Q_{max} is below this value.

<u>Lone Pine Creek D-3 A Pool</u>

Views of Hudson's Bay

Hudson's Bay submitted that the water-gas ratio for the well in Legal Subdivision 6 of Section 33, Township 30, Range 27, West of the 4th Meridian, has remained relatively constant and asked that a drawdown factor of 0.85 be retained for the well. It stated that since the well in Legal Subdivision 2 of Section 29 is permitted to produce the oil accumulation and the associated gas cap concurrently the production of gas is related to the oil allowable and therefore no gas production restriction is required. It requested that if a maximum daily gas rate is assigned to the well, a drawdown factor of 0.75 be applied.

Views of Dome

Dome stated that there has been no significant water production from the well in Legal Subdivision 10 of Section 32, Township 30, Range 27, West of the 4th Meridian, and accordingly requested that no change be made to the maximum daily allowable for this well.

Views of the Board

The Board is satisfied that the instances in which the suggested Q_{max} rate was exceeded for the well in Legal Subdivision 6 of Section 33 were not deliberate contraventions of the Q_{max} rates. The Board notes that the 1972 Q_{max} rate will be less than 1.4 MMcfd for the referenced well and since the water cut has remained fairly stable over the past 18 months, it has decided to continue the current drawdown factor for the well at 0.85.

The well in Legal Subdivision 2 of Section 29 is classified as an oil well and has had no Q_{max} rate assigned. Recent production history does not indicate a Q_{max} should be assigned to the well.

The Board agrees with Dome that a drawdown factor of 0.85 is appropriate for the well in Legal Subdivision 10 of Section 32.

Nevis Devonian Pool

Views of CIGOL

CIGOL stated that the recent recompletions carried out at the wells in Legal Subdivision 10 of Section 10 and Legal Subdivision 10 of Section 15, both in Township 40, Range 22, West of the 4th Meridian, appear to have resulted in reduced water production. It stated that the gas-water contact in Unit No. 2 appears to be some 5 to 10 feet higher than the original level. Notwithstanding the water production problems, CIGOL asked that the present drawdown factor of 0.80 be used in determining the maximum daily allowable rates for the wells in Unit No. 2.

Views of Chevron

Chevron submitted that water production is not a serious problem in Unit No. 1. It stated that water production has been inhibited or prevented by the presence of sections of low vertical permeability in the reservoir. Chevron indicated that following the rework on the well in Legal Subdivision 11 of Section 30, Township 39, Range 21, West of the 4th Meridian the water production for the well was reduced to a level consistent with water of condensation. Chevron asked that the current drawdown factor of 0.80 be continued for the wells in the pool.

Views of the Board

The Board notes that the wells in Legal Subdivision 10 of Sections 10 and 15, referred to by CIGOL, have shown a decrease in water production following recent workovers, but it is not entirely convinced that water production from the wells is independent of gas production rates. The Board accepts Chevron's contention that the well located in Legal Subdivision 11 of Section 30 is producing only water of condensation.

The Board is prepared to maintain the current drawdown factor of 0.80 for the entire pool, with the exception of the two wells referred to above operated by CIGOL. Until the production performance of these two wells can be further evaluated, the Board believes that drawdown factors of 0.85 for the well in Legal Subdivision 10 of Section 10, and 0.90 for the well in Legal Subdivision 10 of Section 15, are appropriate.

Pendant D'Oreille Mannville A Pool

Views of Home

Home asked that the wells in this pool be permitted to produce at rates consistent with good production practice, or if if a Q_{max} rate is desirable that a drawdown factor of 0.80 or less be used. It submitted that the Q_{max} rates for the wells, Home CMG Pendor 7-17-3-8 and Home CMG Pendor 7-18-3-8, were exceeded during the past year "in order to keep these wells viably productive".

Views of Hudson's Bay

Hudson's Bay stated that the well, HB Pend D'Oreille 10-8-3-8, produces water at a rate consistent with water of condensation and asked that a drawdown factor of 0.75 be used to calculate the Q_{max} rate.

Views of the Board

Based upon past production performance, the Board is prepared to accept the less restrictive drawdown factors recommended by Home and Hudson's Bay for wells in this pool.

The request for a drawdown factor of 0.80 or less for all wells in the pool does not seem warranted at this time in view of the production performance. However, the Board will set a drawdown factor of 0.80 for the wells in Legal Subdivision 10 of Section 7, Township 3, Range 8, West of the 4th Meridian and Legal Subdivision 10 of Section 8, Township 3, Range 6, West of the 4th Meridian. These wells produce only water of condensation and have over 20 feet of gas pay. The wells in Legal Subdivision 10 of Section 5 and Legal Subdivision 6 of Section 16 have less than 20 feet of pay and have produced water in excess of formation water, and therefore the Board believes that a drawdown factor of 0.85 is appropriate for each well.

For the wells in Legal Subdivisions 7 of Sections 17 and 18 the Board will establish a Q_{max} rate of 0.7 MMcfd for each well as proposed by the operator in order to minimize operating problems associated with production from these two wells.

The Board is concerned with the number of instances in which assigned Q_{max} rates were exceeded and therefore will set maximum daily production rates by Board Order.

Pine North-west D-3 A Pool

Views of Hudson's Bay

Hudson's Bay asked that no change be made to presently assigned Q_{max} rates, and also that it be permitted to exceed each assigned Q_{max} rate by as much as 500 Mcfd to absorb pressure fluctuations in the main transmission line to the Windfall gas plant. It submitted that well flowing characteristics have not changed during the past year, and that aquifer response will maintain the pool pressure at 4300 psia at current withdrawal rates.

Views of the Board

The Board has reviewed the effect on pool pressure caused by expansion of the aquifer and agrees that, in the absence of new deliverability data, no adjustments to the existing Q_{max} rates are required for the 1972 calendar year. In order to alleviate the operating problems associated with line pressure fluctuations and hydrate plugging, the Board believes the request for 500 Mcfd operating flexibility in excess of the calculated Q_{max} to be reasonable in this case. The Board would expect the operator to schedule the production from the pool in a manner to minimize the occurrences of exceeding the assigned Q_{max}.

Windfall D-3 A Pool

Views of Fina

Fina asked that Q_{max} restrictions be removed from wells in the Windfall D-3 A Pool. Fina stated that gas wells in the East lobe of the pool do not have the production capacity to meet present Q_{max} rates. It also stated that in accordance with the terms of Approval No. 382, which requires that every reasonable effort be made to maximize oil production from the pool, all wells producing oil should be allowed to produce without any Q_{max} restrictions.

Views of the Board

The Board is satisfied with the current production rates and pool performance, but it is not prepared to remove Q_{max} restrictions at this time. It notes that present Q_{max} rates

are not restrictive to production operations and believes that the 1971 Q_{max} rates should again be assigned for 1972.

DECISION

The Board adopts effective January 1, 1972 the drawdown ("f") factors and the maximum daily gas production rates summarized in Attachment 1.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
December 30, 1971

Attachment 1 to Decision No. 71-19

Summary of Operator Proposals and Board Decision

Pool	Operator Proposals	Board Decision
Gold Creek Wabamun A	Good Production Practice.	Good Production Practice.
Harmattan Elkton D-3 A	Qmax based on coning simulation study and production history.	Adopt Q_{max} as recommended by Canadian Superior except for two wells. Well — Q_{max} Home et al Harm 6-8L-32-4 — 2.0 MMcfd Cdn. Sup Unit Harm 11-16L-32-4 — 3.0 MMcfd
Kaybob South Beaver-hill Lake A	Maximum production rates based on coning simulation studies.	Adopt maximum production rates as recommended by Hudson's Bay and Chevron except for one well. Well — "f" Chevron BLGU 3 Kaybob S 5-23-59-18 — 0.75
Lone Pine Creek D-3 A	No change in current drawdown factor.	No change in current drawdown factor of 0.85.
Lookout Butte Rundle A	Assign drawdown factor of 0.75 or less for all wells. No Q_{max} be set below 3 MMcfd.	Maintain current drawdown factors or minimum Q_{max} rate of 3.0 MMcfd except for three wells. Well — "f" — Q_{max} BA Lookout Butte 11-31-1-28 — 0.85 — - Gulf Unit Lookout Butte 16-12-2-29 — 0.80 — - Gulf Unit Lookout Butte 7-16-1-28 — - — 3.0 MMcfd

Attachment 1 to Decision No. 71-19 (Continued)

Pool	Operator Proposals	Board Decision
Nevis Devonian	No change in current drawdown factor	Maintain current drawdown factor of 0.80 except for two wells Well — "f" A.P. Can Home TENN Nevis 10-10-40-22 — 0.85 IOE Nevis 10-15-40-22 — 0.90
Pendant D'Oreille Mannville A	Hudson's Bay - use f = 0.75 for well in LS 10-8. Home - Good production practice or "f" factor of 0.80 or less.	Reduce drawdown factors. Assign Q_{max} rates by Board Order Well — "f" — Q_{max} (Mcfd) HB Pendant D'Oreille 10-8-3-8 — 0.80 — 7800 Home CMG Pendor 10-7-3-8 — 0.80 — 950 Home CMG Pendor 10-5-3-8 — 0.85 — 900 Home CMG Pendor 6-16-3-8 — 0.85 — 620 Home CMG Pendor 7-17-3-8 — - — 700 Home CMG Pendor 7-18-3-8 — - — 700
Pine Northwest D-3 A	No change in current Q_{max} rates. Operating flexibility of 500 Mcfd in excess of Q_{max}.	No change in current drawdown factor of 0.95 with operating flexibility of 500 Mcfd in excess of the Q_{max} rate.
Windfall D-3 A	Revoke Q_{max} restriction for all wells.	No change in current Q_{max} rates.

ENERGY RESOURCES CONSERVATION BOARD

Decision 72-1
Application No. 5958

EXPANSION OF OIL HANDLING CAPACITY AND INSTALLATION OF MISCIBLE FLUID PRODUCTION FACILITIES RAINBOW FIELD

THE APPLICATION AND HEARING

Mobil Oil Canada, Ltd. applied pursuant to section 38, clause (b) of The Oil and Gas Conservation Act for approval of a scheme to expand oil handling capacity and install miscible fluid production facilities at its battery located in Legal Subdivision 10 of Section 1, Township 110, Range 6, West of the 6th Meridian in the Rainbow Field. The existing battery would be expanded to a design capacity of 25,000 barrels of saleable oil daily. Gas from the battery would be processed in new refrigeration facilities for the production of 16.6 MMscf/d of miscible fluid, 0.9 MMscf/d of plant fuel gas and 2.8 MMscf/d of residue gas. The miscible fluid would be injected into the Rainbow Keg River AA Pool, presently under pressure maintenance by a gas injection scheme operated under Approval No. 1410. The residue gas would be injected into the gas cap of the same pool. Mobil Oil Canada, Ltd. submitted a separate application (Application No. 6019) for approval to place the Keg River AA Pool under miscible flood.

The main purpose of the hearing was to consider whether the system would provide acceptable fluid production measurement accuracy for each of the 19 pools with a total of 25 wells tied to the battery.

There were no submissions of intervention.

The application was heard at the offices of the Energy Resources Conservation Board, Calgary on December 6, 1971 by Examiners G. J. DeSorcy, P. Eng. and N. A. Strom, P. Eng.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used In Report
Mobil Oil Canada, Ltd.	W. Rama, P. Eng. R. A. Slotboom, P. Eng.	Mobil
Board Staff	L. E. Hicklin, P. Eng. P. M. Stanton, P. Eng.	Board

SUBMISSION OF MOBIL

Mobil submitted that the oil, gas and water produced from a total of 19 pools and 25 wells would be delivered to the subject battery where there would be four stages of separation, the third stage being at 250°F and 5 psig. The attached Figures 1 and 2 taken from the application are schematic diagrams of plant inlet and outlet streams. Figure 1 shows approximate fluid volumes and pressures and temperatures of processing. Figure 2 shows existing and proposed facilities. In addition to proposed metering points, there would be continuous chromatographic analysis as a process control measure. The test production measured at five satellites operating at pressures and temperatures ranging from 350 to 450 psig and 60° to 100°F respectively, would be adjusted to hypothetical battery conditions of 140° to 150°F and 40 psig by employing flash calculation estimates. The group oil production would be metered at the end of the processing and the group gas production would be determined by metering the gas volumes from the inlet separator and heater treaters and by estimating the volume from the flash vessel operating at 5 psig and 250°F. The group oil and gas production would then be adjusted by flash calculation estimates to the hypothetical battery conditions. Group production would then be prorated to wells in the usual manner, based on the adjusted test production for each well.

Mobil submitted evidence intended to demonstrate that production measurements for each well would be determined with predicted error ranges as follows:

	Maximum	Predicted
Oil	± 3.2%	± 1.9%
Gas	± 4.0%	± 2.4%
Water	± 5.2%	± 3.0%

Mobil estimated well test flow errors by combining measurement, sampling and flash adjustment errors from satellite testing of wells. Similarly it determined errors of group measurement as a combination of meter and flash adjustment errors. After prorating group flow to individual wells, the overall error for a well then becomes the aggregate of errors in well test flow, the sum of well test flows and group flow.

BASIS OF CONSIDERATION

The examiners are generally satisfied with the measures proposed for the conservation of hydrocarbons and for the control of pollution. The principal concern of the examiners, and in fact the major reason for the hearing, is the accuracy in measuring production.

The Board normally requires that production for individual pools be determined within the following accuracies:

Oil	± 2%
Gas	± 5%
Water	± 5%

The question of what measurement accuracy would result from Mobil's proposal is discussed under the following subheadings:

(a) Group Oil Measurement

(b) Group Gas Measurement

(c) Well Oil Measurement

(d) Well Gas Measurement

(e) Error in Estimated Battery Production Based on Sum of Test Flows

(f) Resulting Errors in Prorated Flow to Well.

Mobil employed a mathematical method which combined errors on a statistical basis, incorporating the assumption that all errors would have a Gaussian or Normal type statistical distribution. The examiners accept the method used by Mobil, however they feel that it is highly idealized in that practical experience has indicated the error distribution is not Gaussian for some of the parameters under investigation. The effect of the assumption is that in many cases the errors calculated will tend to be somewhat lower than would be experienced in practice.

In determining measurement accuracies, Mobil submitted several error predictions indicating the degree of confidence and the mathematical method used to combine errors. The examiners are primarily interested in the category which was submitted as being the "probable combination of the predicted errors". A detailed description of the method of error analysis is included in Appendix 1.

(a) Group Oil Measurement

(1) Views of Mobil

Mobil proposed to use the Rainbow Pipeline sales oil meter as a primary basis for determining group oil production. The sales oil volume would be corrected to the hypothetical battery conditions by means of flash calculations. In answer to questions, Mobil stated there might be an oil metering error of $\pm$ 0.34% and a further error of $\pm$ 0.67% in adjusting the measured oil to the hypothetical conditions by flash calculations. Combining these two errors[1], Mobil contended that the error in group oil measurement would be $\pm$ 0.75%.

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(1) Appendix 1 - Type 1.

(2) Views of the Examiners

The examiners estimate that, for the existing facilities, the error involved in determining volume changes by the use of flash calculations is ± 10.0% of the calculated incremental volume. Since the volume change is expected to be in the order of ± 10.0% of the initial volume, the errors that can be assigned to this initial volume would be ± 1.0%. Therefore the examiners believe that an error of ± 1.0% can arise due to the adjustment of sales oil volumes to the hypothetical battery conditions. The examiners further believe that an oil metering error of ± 0.5% is applicable. Combining errors(1), the examiners conclude that a probable error of ± 1.1% would be realistic for reported group oil production in accordance with the scheme proposed by Mobil.

(b) Group Gas Measurement

(1) Views of Mobil

Mobil proposed to measure the gas volumes off the inlet separator and the three heater treaters with orifice meters and to estimate, by flash calculations, the gas from the 5 psig vessel. The combined volume of the five gas streams would be adjusted to the hypothetical battery conditions by flash calculations.

In reply to questions, Mobil stated there might be an error of ± 0.89% associated with each orifice meter and an error of ± 0.67% in adjusting the gas volumes to hypothetical conditions. After allowing for the different volumes of gas in each stream, Mobil estimated(4) that the error in the reported group gas production would be ± 0.98%.

(2) Views of the Examiners

After examining reports by the Board staff(2) and the CIM-AIME(3) study group, the examiners estimate that the error associated with orifice metering is ± 3.0% assuming first class metering with excellent gas gravity data.

As previously discussed, the examiners believe that the error in flash calculations would be about ± 10.0%. This error based on the total gas production when adjusting measured gas back to hypothetical battery conditions would be about ± 1.5% for a volume change in the order of ± 15.0%.

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(1) Appendix 1 - Type 1.

(2) A Report on the Inherent Errors in Orifice Metering and the Evaluation of Certain Variables Involved in Gas Flow Measurement by L. E. Hicklin, June, 1963.

(3) A Report on Gas Flow Measurement by N. A. Cleland and K. Aziz, Journal of Canadian Petroleum Technology, Volume 1, No. 3 Fall, 1962.

(4) Appendix 1 - Type 1 and Type 2.

Combining the above errors(1), the examiners conclude that a probable error of ± 3.4% would apply for reported group gas production at Battery 10.

(c) Well Oil Measurement

(1) Views of Mobil

Mobil proposed to measure test oil volumes at satellite conditions and to adjust these volumes to the hypothetical battery conditions by flash calculations.

Mobil stated that there could be an oil metering error of ± 0.34% and an oil meter proving error of ± 0.17% at the satellites. Mobil defined "accuracy of sample error" as that error which resulted from using test rates to estimate monthly well production as opposed to continuous measurement at the test separator. Mobil estimated this error to be ± 1.33% assuming four 24-hour tests per month. Mobil concluded(1) that the error in estimating monthly oil production for a well based on test flow would be ± 1.38%. In reply to a question, Mobil stated that it had not accounted for possible error as a function of absolute level of production. In other words, the same percentage error would apply to a well producing at 3000 BOPD as that for a well producing at 100 BOPD.

During questioning, Mobil agreed that because the proving of meters required a repeatibility of ± 1.5% (the maximum liquid oil meter proving error allowed by Board regulations) it was possible for individual wells to have errors equal to ± 1.5%.

Mobil stated that the proposed operating plan was to use computer monitoring of test rates. The monitoring would generally operate such that corrective actions would be initiated when the test rate varied by about ± 7% or more from the predicted rate.

(2) Views of the Examiners

The examiners believe that test liquid meter proving may introduce an error of ± 1.5%. The examiners also believe than an oil metering error of ± 0.5% would apply and that the proposed adjustment from test to hypothetical battery conditions by flash calculations introduces a further error of approximately ± 1.0%.

Board staff have investigated the relationship between the magnitude of the producing test rate at a well and the significance of using this test rate to estimate monthly production. From information collected to date it was generally evident that the so called "accuracy of sample error" varies inversely with the normal production level. For the range of individual well production rates involved (70 BOPD to 3600 BOPD), this error is estimated to vary from ± 1.5% for the 3600 BOPD well

(1) Appendix 1 - Type 1.

to ± 7.0% for the 70 BOPD well, assuming four well tests per month. The examiners are of the opinion that this source of error, not provided for in Mobil's analysis, must be included in determining overall probable error for estimating production on the basis of individual well test flows.

Combining all sources of error(1), the examiners conclude that reported oil production of individual wells based on test flows would have an error range of ± 2.4% for wells producing at 3500 BOPD to ± 7.2% for wells producing at 70 BOPD. A summary of existing pool and well production rates and satellite conditions is contained in Table 1. The major error component is that introduced by magnitude of the well test rate. More frequent testing of low volume well streams combined with a processing system which would keep larger volume pools separate from smaller volume pools until adequate group measurement was obtained is a possible means of reducing the overall error to an acceptable level.

(d) Well Gas Measurement

(1) Views of Mobil

Mobil proposed to measure test gas volumes at satellite conditions and to adjust these volumes to the hypothetical battery conditions by flash calculations. The frequency of well testing is the same as for test oil measurement, namely, four tests per month.

In answer to Board questions, Mobil stated there could be an error of ± 0.89% associated with orifice metering. The "accuracy of sample" error was estimated to be ± 1.33% and an error of ± 0.67% was estimated for the conversion of test gas volumes to equivalent volumes at hypothetical battery conditions. Mobil concluded(1), based on the above factors, that the combined error in test gas measurement would be approximately ± 1.74%.

Mobil developed a set of curves using flash calculations based on the pressure-volume-temperature (PVT) analysis and reservoir fluid composition of each pool to calculate the additional amount of gas that would be flashed between test separator temperature and pressure and the temperature and pressure at the hypothetical battery. During examination, Mobil stated that this correction method took into account the three stages of separation that presently exist. In using the curves, monthly average operating conditions and monthly average fluid compositions would be employed. Mobil stated that it did not perform any type of sensitivity analysis to determine errors attributable to daily variations in operating conditions nor to daily variations in composition of the combined well flow streams being processed.

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(1) Appendix 1 - Type 1.

(2) Views of the Examiners

As discussed previously under Group Gas Measurement, the examiners estimate the probable error associated with orifice metering to be ± 3.0%, substantially higher than Mobil's estimate of ± 0.89%. With respect to the adjustment of test gas volumes to hypothetical battery conditions, the examiners have considered the effects of inherent errors in flash calculations, variations in operating conditions of the various stages of separation, variations in fluid mixtures, and changing pool composition with production (especially for the AA Pool when subject to solvent flooding). Considering these potential variances, the examiners conclude that the error in correcting individual well test gas volumes to hypothetical conditions would be about ± 5.0%.

In accordance with Board staff studies concerning errors of sampling as discussed under Well Oil Measurement, the examiners observe that the error varies inversely with the level of production. This error is estimated to vary from ± 2.0% to ± 8.0% for wells at Battery 10.

Considering all sources of error, the examiners conclude[1] that an error range of ± 6.2% to ± 9.9% would apply for reported individual well gas measurement based on well test flow. As in the case of Oil Test Measurement, a large component in the source of error is that related to level of production.

(e) Error in Estimated Battery Production Based on Sum of Test Flows

(1) Views of Mobil

Mobil estimated the error in the calculated battery production based on the sum of test flows for all wells to be ± 1.03% for oil and ± 1.33% for gas. The levels of errors are governed by the extent of errors applicable for individual well test flows.

(2) Views of the Examiners

Using Mobil's approach and applying the estimates determined by the examiners, it is concluded that the error in the sum of test flows would be about ± 1.8% for oil and ± 4.6% for gas.

(f) Resulting Errors in Prorated Flow to Well

(1) Views of Mobil

Mobil submitted an error estimate for the prorated flow to a well based on the combining of errors associated with the individual well test flows, the sum of the test flows of all wells and the measured group flow at the battery. Mobil estimated[1] the error for reported production

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(1) Appendix 1 - Type 1.

of each well in Battery 10 to be $\pm$ 1.87% for oil and $\pm$ 2.40% for gas. A summary of sources of error and resulting final errors as estimated by Mobil and by the examiners is shown in Table 2.

(2) Views of the Examiners

Using the same method of mathematically combining errors as adopted by Mobil, but introducing their own judgement of probable errors from a given source, the examiners conclude[1] that an error range of $\pm$ 3.2% to $\pm$ 7.5% is applicable for reported oil production for wells tied to the battery. Similarly, an error range of $\pm$ 8.4% to $\pm$ 11.4% is estimated for the reported gas production for individual wells. The lower errors would apply for wells producing about 1000 BOPD, and the larger errors would apply for wells producing less than 100 BOPD. Since battery group measurement accuracy appears to be relatively good (about $\pm$ 1.0% for oil and $\pm$ 3.5% for gas), a method of improving accuracy for individual wells would be to operate selected pools and wells in separate process batteries.

SUMMARY OF EXAMINERS VIEWS

The examiners have reviewed the evidence provided in light of the Board's general objective for pool measurement accuracy of $\pm$ 2% for oil, $\pm$ 3% for gas and $\pm$ 5% for water. The examiners believe that a combination of factors will make it impractical to meet those standards for all pools tied into the proposed Mobil Battery 10 facility.

The always present errors of metering, sampling and adjusting make it difficult to meet the standard even in relatively simple batteries involving only one pool. Mobil's Battery 10 includes 19 pools for which the attainment of reasonable measurement accuracy is particularly hindered because test measurement is obtained at satellites operated at pressures far above those of the hypothetical or reference level (ie. 350 to 450 psig versus 40 psig), and also, because wells of highly different capacity (ie. 4000 BOPD versus 100 BOPD) are commingled as they enter the battery and before reasonably accurate measurement is obtained.

The examiners recognize that Mobil's proposed battery is an expansion of an existing facility and in fact involves upgrading of control devices such that measurement may be improved over that experienced in the past. In these circumstances, the examiners believe that the most practical approach is to establish standards of accuracy having regard for the sizes and types of pools involved (as outlined in Table 3) and the modifications, and additions that could be reasonably made to the existing facilities.

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(1) Appendix 1 - Type 1.

On that basis, the examiners believe that the Board's general standards should apply to the AA Pool. For the EE Pool, the II Pool and the JJ Pool, and in these particular circumstances, the examiners believe that the standards can be relaxed by about 1.0% or in other words ± [illegible]% for oil, ± 4% for gas and ± 6% for water. The remainder of the pools are quite small and on this basis the examiners would accept a further relaxation in the standards to about ± 5% for oil, ± 10% for gas and ± 10% for water.

RECOMMENDATIONS

(1) Concerning the Application

The examiners recommend that the Board grant the application for oil handling and miscible fluid production facilities subject to

(a) the addition of vessels and metering devices at Battery No. 10, not later than the end of 1972, such that the flows from the AA Pool may be measured
   (1) after the first stage of separation (at 100 psig and 100°F) and
   (2) before commingling with production from other pools,

(b) the addition of vessels and metering devices at the satellite batteries not later than the end of 1972, such that the flows from each of the EE Pool, the II Pool and the JJ Pool may be measured continuously before commingling with production from other pools,

(c) the addition of metering devices so that the commingled flow excluding the AA Pool is measured at the first stage of separation in order that production from the EE Pool, II Pool and JJ Pool, adjusted to inlet separator conditions, can be subtracted from the total production in order to obtain the total production of the remaining pools in this battery.

(2) Concerning Board Approval of Batteries Receiving Production From More Than One Pool

Production measurement accuracy is a function of metering errors, sample errors and proration errors. Both of the latter sources of error are influenced by the design of the production facilities and the operating practices. Therefore, for all fieldgate, satellite batteries, the Board should require that operators submit an application and obtain approval before constructing this type of production battery facility.

VIEWS OF THE BOARD

The Board agrees with the recommendation of the examiners.

DECISION

The Board has adopted the recommendation of the examiners.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
March 6, 1972

TABLE 1

East Rainbow Test Separator

Capacities and Maximum Well Flows

From Data Submitted by Mobil

Satellite 2:

Operating Conditions: 450 psig and 100°F

Test separator	-	48" x 18' vertical.
Liquid capacity	-	10,000 BOPD.
	-	4' fluid level, 1 minute retention.
Gas capacity	-	12 MMSCFD.

Well streams	Current Max. Rates Oil (BOPD)	Gas (MSCFD)
4-13 AA	3300	750
2-14 AA	1300	760
10-14 AA	4000	1040
12-13 AA	2700	1050
16-28 DDD	650	612
	11950 BOPD	4212 MSCFD

Satellite 3:

Operating Conditions: 350 psig and 60°F

Test separator	-	36" x 8' vertical.
Liquid capacity	-	4,000 BOPD.
	-	3' liquid level, 1 minute retention.
Gas capacity	-	6.7 MMSCFD.

Well streams	Current Max. Rates Oil (BOPD)	Gas (MSCFD)
8-33 QQ	700	465
8-33 G	170	169
12-03 EE	2100	823
2-12 SS	200	100
5-32 3G	500	250
12-3 Gas makeup		4000
	3670 BOPD	5807 MSCFD

Table 1 (contd)

Satellite 4:

Operating Conditions: 350 psig and 50°F

Test separator - 36" x 8' vertical

Liquid capacity - 4000 BOPD

Gas capacity - 6.7 MMSCFD

Well streams	Current Max. Rates Oil (BOPD)	Gas (MSCFD)
10-08 JJ	950	735
6-06 II	550	546
12-06 II	2800	1440
2-28 F	80	80
11-28 F	350	470
11-28 C	50	100
	4780 BOPD	3371 MSCFD

Satellite 5:

Operating Conditions: 375 psig and 60°F

Test separator - 36" x 8' vertical

Liquid capacity - 4000 BOPD

Gas capacity - 6.7 MMSCFD

Well streams	Current Max. Rates Oil (BOPD)	Gas (MSCFD)
5-10 30	400	110
4-07 RR	200	135
6-06 VV	200	130
5-11 KK	700	246
	1500 BOPD	621 MSCFD

TABLE 1 (contd)

Satellite 6:

Operating Conditions: 350 psig and 70°F

Test separator - 36" x 10' vertical.

Liquid capacity - 5,000 BOPD.

Gas capacity - 6.7 MMSCFD.

Well streams	Current Max. Rates Oil (BOPD)	Gas (MSCFD)
15-16 OO	330	340
15-16 I	800	830
13-16 F	550	570
4-15 C	330	340
4-15 3R	550	570
	2560 BOPD	2650 MSCFD

TABLE 2

Summary of Errors as Estimated by Mobil and by the Examiners

	Error for Individual Well Test Flow (1)	Error for Estimated Battery Production from Sum of Well Test Flows (2)	Error for Group Flow of Battery (3)	Resulting Error f[illegible] Well After [illegible] (4)
il				
obil	± 1.38%	± 1.03%	± 0.75%	± 1.8%
xaminers	± 2.4% - 7.2%	± 1.8%	± 1.1%	± 3.2% - 7.5%
s				
bil	± 1.74%	± 1.33%	± 0.98%	± 2.40%
aminers	± 6.2% - 9.9%	± 4.6%	± 3.4%	± 8.4% - 11.4%

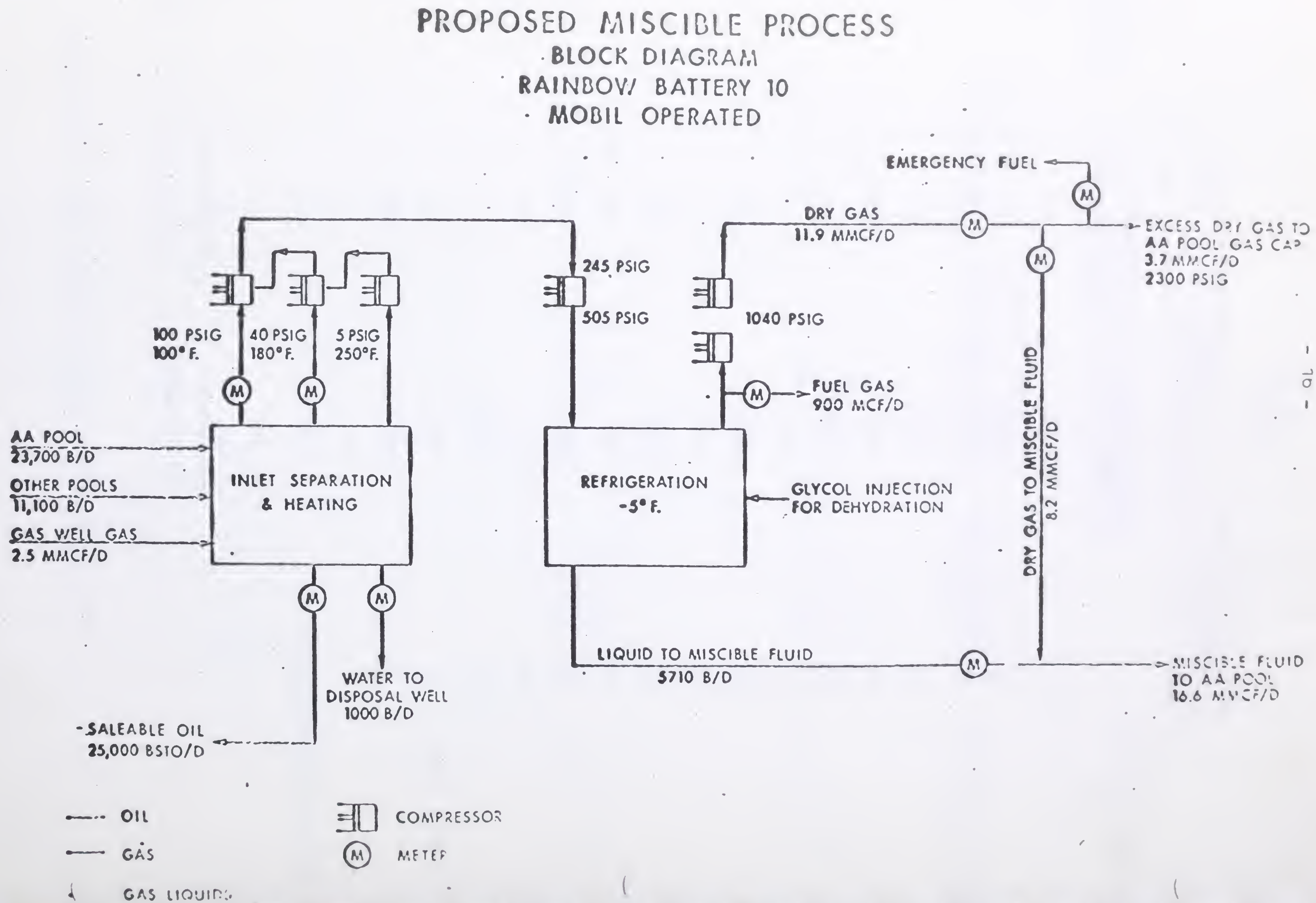
TABLE [illegible]

Summary of Recoverable Reserves, Cumulative Production and Remaining Reserves of Pools Supplying Mobil Rainbow Battery 10

Pool Name	Recoverable Reserves (MSTB)	Cumulative Production (MSTB) (Nov. 30/71)	Remaining Reserves (MSTB)
Rainbow Keg River AA	67,000*	6,425	60,575
EE	8,030	818	7,212
II	14,700	2,054	12,646
JJ	7,500	910	6,590
KK	1,920	206	1,714
QQ	4,030	418	3,612
VV	660	75	585
DDD	2,980	276	2,704
OOO	697	41	656
OO	1,030	134	896
RR	909	155	754
SS	1,650	116	1,534
GGG	1,430	16	1,414
III	438	2	466
Rainbow Muskeg CC	479	57	422
F	1,500	168	1,332
G	150	18	132
Rainbow Sulphur Point B	238	19	219
C	200	17	183
F	807	36	771
	116,378 MSTB	11,961 MSTB	104,417 MSTB

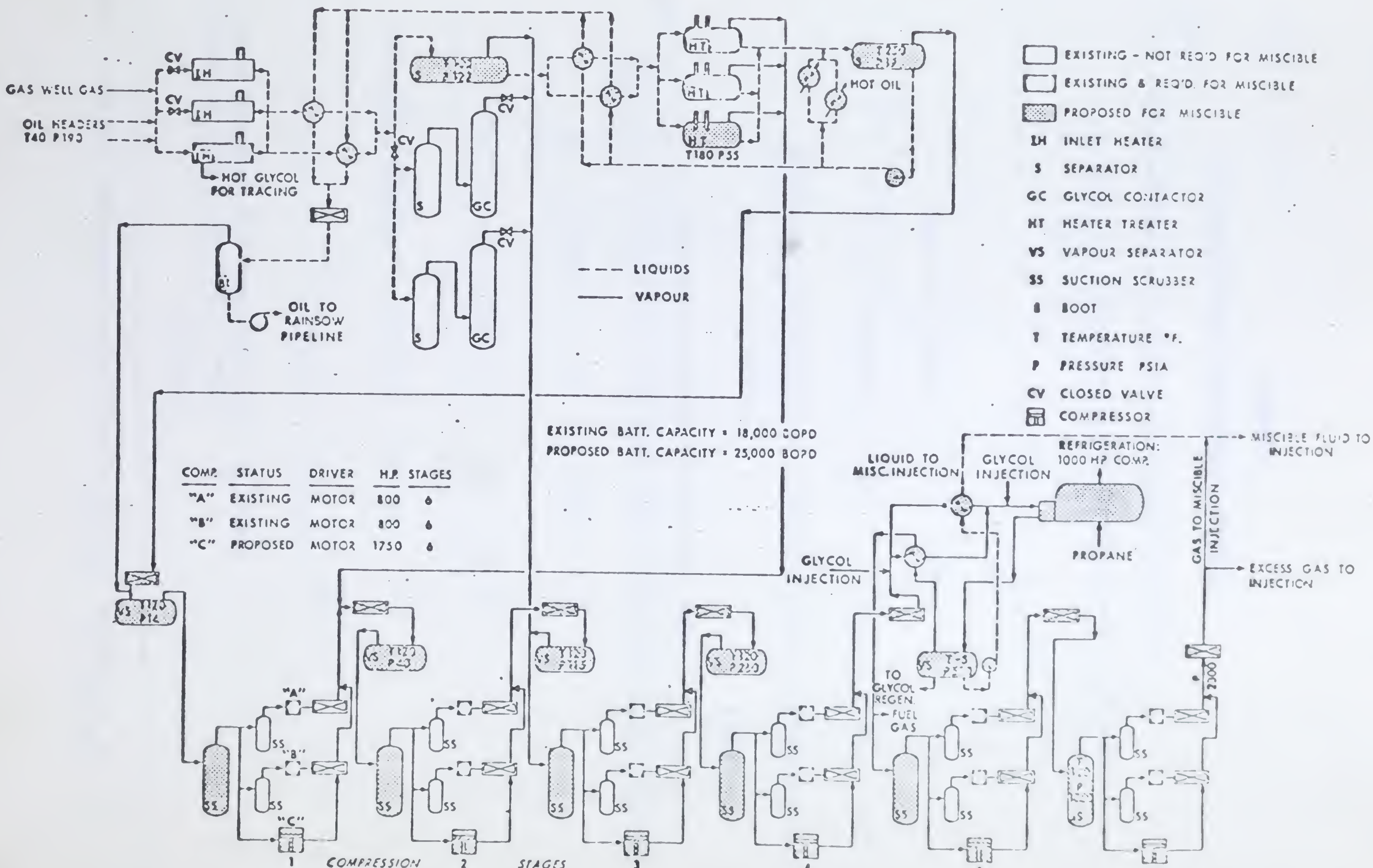
* This value will increase to 85,000 under solvent flood

FIGURE 1


PROPOSED MISCIBLE PROCESS
BLOCK DIAGRAM
RAINBOW BATTERY 10
MOBIL OPERATED
EMERGENCY FUEL
DRY GAS
11.9 MMCF/D
EXCESS DRY GAS TO
AA POOL GAS CAP
3.7 MMCF/D
2300 PSIG
245 PSIG
505 PSIG
1040 PSIG
100 PSIG
100° F.
40 PSIG
180° F.
5 PSIG
250° F.
FUEL GAS
900 MCF/D
DRY GAS TO MISCIBLE FLUID
8.2 MMCF/D
AA POOL
23,700 B/D
OTHER POOLS
11,100 B/D
GAS WELL GAS
2.5 MMCF/D
INLET SEPARATION
& HEATING
REFRIGERATION
-5° F.
GLYCOL INJECTION
FOR DEHYDRATION
LIQUID TO MISCIBLE FLUID
5710 B/D
MISCIBLE FLUID
TO AA POOL
16.6 MMCF/D
WATER TO
DISPOSAL WELL
1000 B/D
SALEABLE OIL
25,000 BSTO/D
OIL
GAS
GAS LIQUIDS
COMPRESSOR
METER

FIGURE

PROPOSED MISCIBLE PROCESS
RAINBOW BATTERY 10
MOBIL OPERATED RAINBOW
ALBERTA



NOTE: VS LIQUIDS PUMPED TO VS OF NEXT HIGHEST STAGE
SS LIQUIDS FLOW TO VS OF NEXT LOWEST STAGE

APPENDIX 1

Methods Employed for Combining Errors

The methods employed by Mobil for combining errors can be derived from the following general relationship: [1]

$$\sigma_F^2 = \sum_{i=1}^{n} (\partial F/\partial X_i)^2 \quad \sigma_i^2 \quad \ldots\ldots\ldots\ldots\ldots(1)$$

where σ = standard deviation

σ_F^2 = variance

F = function of n variables x_i, $i = 1, 2 \ldots\ldots\ldots n$

Type 1

Terms multiplied or divided of the form

$$F = (x_1) \quad (x_2)$$

$$\sigma_F^2 = (\partial F/\partial x_1)^2 \quad \sigma_1^2 + (\partial F/\partial x_2) \quad \sigma_2^2$$

$$\sigma_F^2 = x_2^2 \ \sigma_1^2 + x_1^2 \ \sigma_2^2$$

$$\sigma_F^2 = (x_1 \ x_2)^2 \left[(\sigma_1/x_1)^2 + (\sigma_2/x_2)^2 \right]$$

$$* \frac{\sigma_F}{F} = \left[(\sigma_1/x_1)^2 + (\sigma_2/x_2)^2 \right]^{\frac{1}{2}} \quad \ldots\ldots\ldots\ldots\ldots(2)$$

where $\frac{\sigma_F}{F}$ = per cent error in F resulting from per cent errors (σ_1/x_1) and (σ_2/x_2) in component terms x_1 and x_2

(1) O. W. Eshbach, Handbook of Engineering Fundamentals, 2nd Ed., J. Wiley and Sons, Inc., New York.

APPENDIX 1 (cont'd)

Type 2

Terms added or subtracted of the form $F = x_1 + x_2$

Proceeding as above:

$$\sigma_F^{\,2} = (\sigma_1)^2 + (\sigma_2)^2$$

$$\sigma_F = (\sigma_1^{\,2} + \sigma_2^{\,2})^{\frac{1}{2}}$$

$$\frac{{}^{*}\sigma_F}{F} = \frac{(\sigma_1^{\,2} + \sigma_2^{\,2})^{\frac{1}{2}}}{F} \qquad \text{..................(3)}$$

where σ_1, σ_2 = absolute errors of component terms x_1 and x_2.

*NB All errors referred to in the report have a 95% confidence interval and therefore the values calculated as per cent errors employ two standard deviations, ie. 2 σ

For example:

Equation (1) becomes

$$\underset{\text{confidence interval}}{\underset{95\%}{\text{(Percent error in F)}}} = \left[(2\sigma_1/x_1)^2 + (2\sigma_2/x_2)^2\right]^{\frac{1}{2}}$$

ENERGY RESOURCES CONSERVATION BOARD

Decision 72-2
Applications No. 6145 and 6146

APPLICATIONS FOR PERMIT TO CONSTRUCT A GAS PIPE LINE WAINWRIGHT-CHAUVIN AREA

THE APPLICATIONS AND HEARING

McCulloch Gas Processing (Alberta) Ltd. initially applied to the Department of Mines and Minerals on October 12, 1971 pursuant to section 6 of The Pipe Line Act for a permit to construct a gas line for the purpose of gathering and transporting natural gas from the Wainwright-Chauvin Area to the facilities of The Alberta Gas Trunk Line Company Limited along the route shown as a solid black line on Figure 1 to this decision. On instructions from the Department of Mines and Minerals the proposed route of the gas line was published in the Edmonton Journal, Calgary Herald, The Albertan, the Wainwright Star-Chronicle, and the Provost News between October 28 and November 3, 1971. Submissions were received by the Department from a number of producers in the area objecting to the application and from other producers asking that approval of this gas line be delayed until studies by The Alberta Gas Trunk Line Company Limited have been completed. The Alberta Gas Trunk Line Company Limited by a letter dated November 23, 1972 objected to the application and indicated in its objection that it had started studies of the area and asked that a permit not be granted to the applicant. On December 29, 1971, The Alberta Gas Trunk Line Company Limited submitted its application to the Department of Mines and Minerals for a permit to construct a gas line in the same general area as shown by the dotted line on Figure 1.

By proclamation of the Lieutenant Governor in Council section 51 of The Energy Resources Conservation Act came into force on January 1, 1972, thereby transferring the administration of The Pipe Line Act to the Board. Accordingly, the applications of McCulloch and Trunk Line then pending were passed to the Board for disposition. After reviewing the applications and holding discussions with the applicants, the Board decided to consider both applications at a public hearing.

The applications were heard concurrently at a public hearing held by the Energy Resources Conservation Board on February 3 and

February 4, 1972 with G. W. Govier, P. Eng., Vernon Millard and D. R. Craig, P. Eng. sitting.

The following appeared at the hearing:

	Abbreviation of Name Used in Report	Represented by	Witnesses
McCulloch Gas Processing (Alberta) Limited	McCulloch	W.B. O'Donoghue	M.D. Mallory H.J. Sedger B.A. Williams II A.J. Williams L.R. Burroughs, P.Eng.
The Alberta Gas Trunk Line Company Limited	Trunk Line	G.R. Forsyth, Q.C.	S.R. Blair, P.Eng. W.J. Deyell, P.Eng. J.R. Jameson, P.Eng. R.M. Walters, P.Eng. D.C. Kesteven, P.Eng. L.J. Schneider, P.Eng. W. Zborluk
Alberta and Southern Gas Co. Ltd.	Alberta and Southern	R.A. MacKimmie, Q.C.	
BPOG Operations Ltd.	BPOG	D.D. Wright, P.Eng.	
Hudson's Bay Oil and Gas Company Limited	Hudson's Bay	B.F. Sims	
Norse Explorations Ltd.	Norse	P.M. Mathieson, C.A.	P.M. Mathieson, C.A.
Provident Resources Management Ltd.	Provident	J.M. Thomson, Q.C.	
Trans-Canada Pipe Lines Limited	TransCanada	E.W.H. Mallabone	
Village of Chauvin	Village of Chauvin	H. Hjelmeland	H. Hjelmeland

	Abbreviation of Name Used in Report	Represented by	Witnesses
Village of Edgerton	Village of Edgerton	M. Kimball	M. Kimball
Municipal District of Provost No. 52	M.D. of Provost	A. Hauck	A. Hauck
Husky Oil Operations Ltd.	Husky	L. J. Corkill	
Region #7 Unifarm	Unifarm	R. Belanger D. Page	M. Belanger
Town of Wainwright	Town of Wainwright	G. Donaldson	G. Donaldson
Municipal District of Wainwright No. 61	M.D. of Wainwright	S. Chynoweth	S. Chynoweth

Alberta and Southern, BPOG, Hudson's Bay, Husky, Provident and TransCanada intervened for the purposes of cross-examination and argument only.

DEFINITION OF ISSUES INVOLVED

The Board considers the following to be the main issues relevant to the disposition of the applications.

(a) merits of the proposed gas lines to the producers,

(b) merits of the proposed gas lines to local consumers,

(c) the role of Trunk Line in the Province.

The Board has reviewed the design of the gas lines proposed by each applicant and notes that the lines meet the standards of its Pipe Line Division and of CSA standard Z184-1968 "Gas Transmission and Distribution Piping Systems".

MERITS OF THE PROPOSED GAS LINE TO PRODUCERS

(1) Views of McCulloch

McCulloch stated that it has entered into a gas purchase contract with TransCanada for the sale of gas gathered in the Wainwright-Chauvin Area. Under this contract McCulloch would be required to deliver to TransCanada initially a minimum volume of gas of 25 million cubic feet per day (MMcfd). The volume would increase to a minimum of 40 MMcfd by November 1, 1972 or upon completion of a gas line proposed for construction by Trunk Line from the northern part of the "Flat Lake Lateral" to the Cessford delivery point, whichever occurs the earlier. McCulloch submitted that TransCanada would purchase the gas at a price of 20 cents per Mcf increasing by 1/4 of a cent per Mcf per year, with a redetermination of price at the end of each fifth year of the contract.

McCulloch submitted that it had entered into gas purchase contracts with producers which involve about 45 Bcf of gas reserves and had letters of intent that involve some further 63 Bcf of gas reserves. McCulloch estimated that these reserves would represent a combined deliverability of about 30 MMcfd, which was based on a rate equivalent to 25 per cent of the absolute open flow potential of the wells. McCulloch indicated that it would construct the gas line and the related well head, gathering dehydration and compression facilities and also would operate the wells. The price of gas to the producers would be 11 cents per Mcf increasing by 1/4 of a cent per Mcf per year, and would be subject to price adjustments in accordance with the heating value of the gas and escalation as follows: at the end of the first fifth year 80 per cent of any increase in price through redetermination would be passed on to the producer and on subsequent redeterminations 75 per cent of the increase in price would be passed on to the producer. McCulloch estimated the cost of operating the wells, gathering, compression and dehydration of the gas to be three cents per Mcf.

McCulloch said that it would be prepared to gather gas from wells located in the Baxter Lake, South Wainwright, North Wainwright, Edgerton and Chauvin Areas which have an absolute open flow potential of greater than one-half MMcfd.

McCulloch submitted that it is prepared to act as a common carrier of gas for producers who would not enter contracts for the sale of gas to McCulloch. While the tariff has not been established, the price of transporting the gas would be dependent on where the gas originated and how far it would be necessary to transport it. McCulloch expressed the opinion that

its scheme would not place the producer in a less competitive position for the sale of his gas than under the Trunk Line's proposed scheme. The producer could sell its gas to other buyers but TransCanada would necessarily be involved in any negotiations.

(2) Views of Trunk Line

Trunk Line provided a general statement of the background leading to its application. It submitted that historically its role has been to provide a transmission service for natural gas developed and produced in Alberta primarily for purchasers that deliver gas to markets outside of the Province. Trunk Line expressed the opinion that this practice has tended to enhance competitiveness in gas purchasing and has put the initiative of seeking new gas supply and for making reserve appraisals with the purchaser and left the title of the gas in its system with the buyer. Assuming a continuation of past practices Trunk Line would have expected to be advised by TransCanada of its need for additional pipe line facilities for the delivery of gas from the Wainwright-Chauvin Area, but this had not occurred. Upon learning of McCulloch's proposed gas line Trunk Line stated that it had commenced studies of reserves in the area, held meetings with prospective gas suppliers and commenced discussion regarding transmission service agreements with producers in the area. Trunk Line said it had signed service agreements for volumes amounting to about 5 MMcfd of gas.

Trunk Line submitted that its proposed line would more effectively serve the existing reserves and future potential reserves than the McCulloch proposal. It contended that, giving consideration to the geology of the area, the westerly portion is relatively more prospective for new gas discoveries than the eastern portion.

Trunk Line stated that, under the normal practice in the industry, the individual producers would operate the well and the dehydration and field compression facilities. However, Trunk Line would be prepared to provide this service on a tariff basis if requested by the producers. The tariff applicable to the transportation of gas within the Wainwright Area would range from 4 cents per Mcf to 2½ cents per Mcf for volumes ranging from 20 MMcfd to 40 MMcfd respectively. Trunk line estimated that the tariff to transport gas from the junction of the proposed Wainwright-Chauvin lateral and the Flat Lake Lateral to the Alberta-Saskatchewan border to be about one cent per Mcf. Trunk Line further stated that it would be prepared to purchase gas and use it as part of the supply for

its Alberta operations, or resell it to any Alberta consumer who might be interested, or resell it in Alberta to a purchaser who might remove it from the Province.

Trunk Line did not provide an estimate of the well head price of gas, nor the minimum volume of gas from a well that it would be prepared to gather. Trunk Line submitted that it does not believe that its proposed gas line would be of higher risk than the system proposed by McCulloch. Trunk Line stated that, in view of its proposed entry into the gas purchase field, it would not expect its other customers to bear any loss that might occur in the proposed system but would expect its customers to take care of their position at the time of contractual negotiations.

In reply to questioning regarding its proposed route through Camp Wainwright, Trunk Line stated that it had contacted Canadian Forces personnel at Calgary and at Camp Wainwright regarding the proposed route through Camp Wainwright. It stated that the Canadian Forces personnel "did not foresee any problems" of Trunk Line constructing a gas line through the Camp. Trunk Line noted that an oil pipe line owned by Husky crosses the Military Reserve but said that it did not have any knowledge whether there would be any different risk factors involved with a gas line than with an oil line. Trunk Line said it would meet any of the requirements that might arise.

(3) Views of Interveners

Norse submitted that its comparative study of the two proposals indicated that Trunk Line would provide the higher rate of return to the producer. It conceded, however, that if McCulloch were declared a common carrier, its assessment would be changed somewhat. In rebuttal to the Norse intervention, BPOG and Husky submitted that insufficient data had been submitted by Norse to properly assess the economics and that the economics presented may not be applicable to all operators in the area.

Alberta and Southern submitted that it did not favour one proposal over the other and that its interest in the applications was solely related to Trunk Line's application as to the effect it might have on the interests of the major gas purchasers. Alberta and Southern stated that it had no objection to Trunk Line entering a business venture of higher risk than it has been accustomed to providing that the loss that might occur in the operation of the proposed gas line would not be passed on to any other gas purchaser or that the gas purchaser not be adversely affected by Trunk Line's ability to borrow money.

BPOG submitted that it favours the McCulloch proposal because the risk is borne by McCulloch and not by the producer. It recommended that the approval be granted to that application which does not result in the producer underwriting the risk venture.

TransCanada submitted that Trunk Line's application is premature and of a speculative nature. It submitted that Trunk Line has not shown that a permit exists for the removal of gas and that no meaningful transportation contracts have been entered into by the applicant.

Provident submitted that it favoured the Trunk Line proposed gas line since it offers the producers a better opportunity for return of their investment and a possible market for sale of gas to other customers. It expressed the opinion that the line proposed by Trunk Line would permit greater development in the area and greater return to the Province in general.

(4) Views of the Board

The Board has considered the position of each applicant with respect to contracts with producers in the area. McCulloch has purchase contracts and letters of intent for some 108 Bcf of gas which, according to the applicant, would have a delivery rate of 30 MMcfd. The Board notes that this is a delivery rate of 1 MMcfd for each 3.6 Bcf of reserves reflecting a 10 year life. This delivery rate is about double the rate that normally prevails in the industry. The evidence presented by Trunk Line indicated that it had signed service agreements for about 5 MMcfd. Thus, as at the time of the hearing, while neither party was in a dominating contractual position with the producers, the McCulloch position was significantly better than Trunk Line.

With respect to the question of a gas sales contract, McCulloch has a contract with TransCanada for specific volumes and at specific prices. Trunk Line, acting as a common carrier transmission company, does not have any sales contracts but stated that in the event that the producers were unable to sell the gas transported through its system it would purchase the gas on its own account either for resale or for use within its system. On the basis of existing contracts McCulloch is clearly in a stronger position than Trunk Line. However, the Board recognizes that Trunk Line probably has the ability to provide a market for the gas and that the actual differences between the two applicants in this respect is not significant.

The Board agrees with Trunk Line's assessment that the western part of the area to be served by the two proposed pipe lines has a greater potential for gas reserves in that the Viking and Nisku zones in this area would likely yield larger gas pools than the Colony and Sparky zones in the eastern area. While the gas line proposed by Trunk Line appears to be better situated to gather gas from a part of the area of highest probable reserves, the Board believes that the system proposed by McCulloch is not significantly less advantageous and would serve an area south of Chauvin that would not be served by the Trunk Line proposal.

The Board has considered the Trunk Line contention that under its proposal the producers would be in a better competitive position respecting the sale of their gas than under the McCulloch plan. While Trunk Line is perhaps theoretically correct with respect to this flexibility, in actual fact the primary potential purchaser would be TransCanada. The Board expects that regardless of which gas line were constructed TransCanada would purchase the gas.

Under the McCulloch proposal the producer would not have to bear the cost and risks of the gas gathering project. On the other hand, the producer would not share to the full in the rewards should the project be a success. Trunk Line presented various operating possibilities but in general it appears to the Board that these would involve more risk to the producers than the competing proposal. The evidence from the producer interveners suggested that some prefer the McCulloch approach, whereas others prefer the Trunk Line approach.

The Board estimates from the evidence presented at the hearing that the price of gas to the producer under the Trunk Line proposal, as shown on the following table, would range from 15 cents per Mcf to 16½ cents per Mcf depending on the throughput rate. If a net price to the producer of 11 cents per Mcf of gas were used in accordance with the McCulloch proposal then 4 cents per Mcf to 5½ cents per Mcf, depending on throughput rate, would be available to the producer to cover the costs associated with the operation of the wells and installation of compression dehydration and gas gathering facilities. The Board expects that this would be within the range of cost necessary to meet these expenses. The Board therefore concludes that each proposal would provide comparable returns to the producer.

Board Estimate of Price of Gas to Producer under Trunk Line Proposal

	Throughput Rate MMcfd	
	20 - 29	40 and over
Price of Gas at Border, ¢/Mcf	20	20
Tariff from Junction of Flat Lake Lateral to Border, ¢/Mcf	1	1
Tariff for Gathering Gas in Wainwright-Chauvin Area, ¢/Mcf	4	2½
Gross to Producer, ¢/Mcf	15	16½

The Board acknowledges the concern of certain interveners that the major gas purchasers in the Province could be faced with increased gas transmission charges if Trunk Line gathers gas in areas of higher than normal risk, such as the Wainwright-Chauvin Area, and if they were called upon to meet possible deficits. The Board believes that the management of Trunk Line made it clear at the hearing that the economics of such operations would not affect the transportation costs of other customers of Trunk Line.

The Board notes that the gas line proposed by Trunk Line crosses a part of Camp Wainwright designated as "Range Danger Area" shown on a military map of the Camp. The Board has communicated with the Canadian Forces Personnel in Calgary and Camp Wainwright regarding Trunk Line's proposal and understands that Trunk Line and the military personnel have agreed to a slightly amended route whereby the gas line would cross the Camp in a region outside the "Range Danger Area". The local Canadian Forces authorities stressed that while the amended route of the line appears reasonable to it, final approval would be required from the Deputy Minister of the Department of National Defence in Ottawa. The Board notes that the Husky oil line crossing Camp Wainwright is not in the "Range Danger Area". In the event that the crossing would have to be made in the same region as the Husky oil line or elsewhere the Board does not believe that there would be a significant effect on the Trunk Line proposal.

With respect to the merits of each proposed pipe line to the gas producers, the Board concludes that on balance there is little to choose between the two applications.

MERITS OF THE PROPOSED GAS LINES TO LOCAL CONSUMERS

(1) Views of McCulloch

McCulloch submitted that it proposes to supply gas at a reasonable price to the towns, hamlets and residences in the surrounding area. McCulloch estimated that in addition to the towns and hamlets in the area about 39 farm residences are located within one mile of the proposed route and that the volume of gas required to supply the local residences would be about 2 MMcfd. While the local consumers would only be supplied with gas after the contractual commitments to TransCanada had been met, McCulloch expressed the opinion that it would have no problem in supplying gas to the local consumers.

With regard to the questions of the width of the right of way and land surface rental rates McCulloch indicated that it would conduct further economic studies to determine an equitable arrangement. McCulloch further stated that it would by-pass farmsteads by 300 feet and avoid damage to shelter belts.

(2) Views of Trunk Line

Trunk Line submitted that it estimated that approximately 80 farm residences are within one mile of its proposed gas line and that the hamlets of Greenshields and Heath are approximately one-half mile and three miles respectively from the Trunk Line system as compared to 15 miles and 8 miles respectively from the McCulloch system. The only locality not in close proximity to the Trunk Line proposal but close to the proposed McCulloch gas line is the hamlet of Hayter. This hamlet was noted to be about nine miles from "Trunk Line's Unity Lateral". Trunk Line stated that it would be prepared to install gas line taps opposite the local consumer to permit him to obtain a gas supply from its line. Trunk Line said that about the same number of farm residences would be served by the gas gathering lines associated with Trunk Line's proposal as with the McCulloch proposal. Trunk Line submitted that it would provide a long term commitment of gas to the local consumer which would only be possible through a Province-wide grid system. The price of the gas to the consumer would be subject to negotiation. It stated that it would be prepared to discuss with the surface owner the width of right of way and the land surface rental rates. The present policy of Trunk Line would be to construct the line a minimum of 300 feet from any occupied dwelling or farmstead and to avoid damage to shelter belts. It reiterated that it would buy

and resell gas to the local consumer on a full commitment of supply basis without making the supply conditional on availability of supplies of other users or putting any priorities ahead of the local user.

(3) Views of Interveners

The Village of Chauvin submitted that it had conducted feasibility studies of providing gas from nearby wells. It stated that the studies indicated that the project would be too expensive for the Village and that there would be a risk that the reserves would not be sufficient to maintain a continued supply of gas. It said that the financial commitment under the McCulloch proposal would be within the ability of the Village to finance and there would be a guaranteed supply of gas. The Village of Chauvin expressed the opinion that the McCulloch proposed gas line would serve more local residents than the Trunk Line proposal.

The Village of Chauvin submitted that it did not have Trunk Line's proposal available when preparing its submission in support of the McCulloch application. It pointed out that further deliberations by the Village Council would be required before a change in its submission could be considered.

The Village of Edgerton submitted that in considering the availability of natural gas and the economic advantages to the community, it supported the McCulloch application. It stated that it did not have Trunk Line's proposal available when preparing its submission but acknowledged that Trunk Line is now prepared to purchase and sell gas to the local consumer. It expressed concern over the time required for Trunk Line to implement its indicated change in role as a gas purchaser and supplier to the local residents.

The M. D. of Provost submitted the McCulloch scheme would best serve the Municipal District of Provost. The McCulloch proposal would supply gas to the hamlet of Hayter and other rural consumers in the Provost Area and provide an increase in assessment to the Municipal District. It stated that the Municipal District would have little benefit from the Trunk Line proposal because the gas line would not pass through the Municipal District of Provost.

Unifarm stated that it was interested in obtaining a supply of gas for the local residents at a fair price and a proper consideration respecting surface rights and favoured the McCulloch proposal. It stated that it had been approached by McCulloch regarding a gas supply whereas it had not been contacted by

Trunk Line. Unifarm also said that the Trunk Line proposal to cross Camp Wainwright would result in serving fewer residents with gas than by the McCulloch proposal.

The Town of Wainwright indicated support of the McCulloch application. It expressed the opinion that the McCulloch proposal would provide an improvement in the economics of the community by establishing an office and supply depot in the Town.

The M. D. of Wainwright indicated support of the McCulloch application. It stated that McCulloch was the first company to ever approach the local residents concerning a gas supply at a reasonable price. It expressed concern about when Trunk Line would provide the same service.

(4) Views of the Board

The Board notes that the representatives of municipalities intervening at the hearing generally supported the McCulloch application. In part this appeared to be due to a lack of knowledge of the Trunk Line application and also due to the possible benefits to the communities from the McCulloch proposal of locating an operating office and operating personnel in the area. The Board agrees with Trunk Line that the hamlets of Greenshields and Heath would be more readily served by the Trunk Line plan but also agrees that Hayter would be more readily served by the McCulloch plan. The Board notes that about 20 more local farm residences could be serviced with gas by the Trunk Line proposal than by the McCulloch proposal, more or less balancing the population of Hayter. Trunk Line appears to be better able to ensure long term security of gas supply to the local consumers than McCulloch because of the readiness by which gas can be obtained from alternative sources through the Trunk Line system. In the matter of delivery priorities the Board expects that, having regard to the small volumes involved, in practice the contractual commitments of McCulloch would not be so serious a problem as to interfere with the supply of gas to local consumers. On the basis of the benefits to the local consumers there does not appear to be much to choose between the two applications, but having regard for the long term security of a gas supply the Board believes the Trunk Line proposal to have some advantage.

ROLE OF TRUNK LINE IN THE PROVINCE

In 1953[1] the Board, in dealing with applications for permits for the removal of gas from the Province, considered the matter of the efficient development and utilization of the gas resources of the Province with respect both to the present and future requirements of the Province and the markets outside the Province. The Board, after having reviewed the details of various gathering systems proposed by the applicants at that time for the transmission of gas, concluded that "integrated gathering facilities based upon a Provincially controlled Trunk-Line system operating as a common carrier would facilitate conservation, provide for flexibility of development, give maximum protection to the Province and be in the mutual interest of consumers, producers and transporters of natural gas". The Board indicated that the facilities could be operated either as a common carrier or as both a common carrier and a common purchaser; operation as a common carrier would permit full realization of pipe line economics through planned joint use of the facilities, at the same time leaving to the producer and the purchaser for local or extraprovincial markets the matter of negotiation of the terms of sale and purchase, subject to Provincial Regulation. The relevant sections of the Board's report[1] are reproduced in Attachment I.

Acting upon the Board's recommendation the Legislature passed The Alberta Gas Trunk Line Company Act in the spring of 1954. This Act empowered Trunk Line, among other things, to act as a common carrier for gas, to act as a common purchaser of gas, to construct gas pipe lines for the transmission of gas, to purchase, acquire, process, transmit, transport, distribute and sell or otherwise acquire and dispose of gas, and to purify or treat for the removal therefrom hydrogen sulphide or other substances from that portion of the gas required for the market.

In all major instances since 1954 permits issued by the Board under The Gas Resources Preservation Act for the removal of gas from Alberta stipulate that the permittee shall remove only such gas as is delivered through the facilities of Trunk Line. Each permit further requires that the permittee shall supply gas from the pipe line of Trunk Line at a reasonable

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(1) The Petroleum and Natural Gas Conservation Board Report to to the Lieutenant Governor in Council With Respect to the Applications under The Gas Resources Preservation Act of: Canadian-Montana Pipe Line Company. Trans-Canada Pipe Lines Limited, Trans-Canada Grid of Alberta Ltd., and Canadian Delhi Oil Ltd. Western Pipe Lines. November 24, 1953.

price to any community or consumer within the Province or to any public utility requiring gas for such a community or consumer that is willing to take delivery of gas at a point on the pipe line and that, in the opinion of the Board, can reasonably be so supplied by the permittee.

Since the formation of Trunk Line, gas destined for removal from the Province has almost exclusively been transported through the Trunk Line facilities except for a few special cases including the following:

(1) Atlantic Richfield Canada Ltd., the principal producer of gas in the Sedgewick Field, received a permit in October 1969 to install a 4½ inch, 18.9 mile gas line directly from its plant in the Sedgewick Field to the Trunk Line Flat Lake lateral. A licence to operate the gas line was issued in November 1970. Contracts for the purchase of the gas were entered into directly between the producer and TransCanada.

(2) Provo Gas Producers Ltd., a subsidiary of Dome Petroleum Limited, received a permit in August 1969 to install a 6 5/8 inch, 42.6 mile gas line extending from the Castor Field to the Trunk Line facilities near Kessler. A licence to operate the gas line was issued in June 1970. Gas from the Castor Field which is primarily owned by Dome Petroleum Limited is transported 27.6 miles to its Provost Gas Plant in the Provost Field for processing. Processed gas from this plant is then transported through about 15 miles of gas line to the Trunk Line system. Contracts for the purchase of the gas were entered into directly between the producer and TransCanada.

(3) Alberta Eastern Gas Limited in the Medicine Hat Area received a permit in October 1970 to install 21 miles of gas line, ranging in sizes from 4½ inches to 8 5/8 inches, to transport gas gathered from its own and other gas wells in the Medicine Hat Field for delivery to a gas line operated by Many Island Pipelines Limited, a subsidiary of Saskatchewan Power Corporation. A licence to operate the gas line was issued in June 1971. Alberta Eastern Gas Limited and other owners in the area have made a sales contract for the gas with Many Island Pipelines Limited.

(4) Alberta Eastern Gas Limited in the Alderson Area received a permit in July 1969 to install a 6 5/8 inch, 13.2 mile gas line to transport gas primarily from its wells in the Alderson Field to Trunk Line. A licence to operate the gas line was issued in April 1970. The gas transported through the line is under contract to TransCanada. (A second

permit was granted to Alberta Eastern in September 1970, to extend its Alderson Area gas line some 51 miles to gather additional gas volumes from wells in the area. The purpose of this line was to supplement the original line. This gas line which was to consist of about 51 miles of sizes varying from 10 3/4 inches to 12 3/4 inches has not been built.)

(5) Provo Gas Producers Limited in the Wildunn Creek Area installed a 4½ inch 17 mile gas line from its own and other gas wells in the Wildunn Creek Field to the Trunk Line facilities. Gas from the Richdale Field in which Dome has an interest is also transported through the line. Gas wells on the route of this gas line are tied into this system. The gas from these two fields is under contract to TransCanada. Construction of the line was undertaken without the Department of Mines and Minerals' prior approval. No permit was issued for the construction of this line but a licence to operate it was issued in April 1964.

(6) Many Islands Pipelines Limited in the Medicine Hat Area installed a 10 3/4 inch, 16.8 mile gas line in 1958 and 1959 to gather gas primarily from its leases within the Medicine Hat Area for delivery to Saskatchewan Power Corporation. No permit was issued for this gas line but a licence to operate the line was issued in March 1961.

(7) Canadian-Montana Pipe Line Company constructed a 16 inch, 18 mile gas line to transport gas gathered from wells in the Pakowki Lake Field for export from the Province through the Montana Power Company system. This line receives gas gathered by the Canadian-Montana Pipe Line Company gathering system which services its wells and other wells in the area. This line has been in operation since February 1952 under authorization of the Federal and Provincial Governments.

(8) Gulf Oil Canada Limited in October 1964 was granted a permit to install a 6 inch, 6 mile gas line and in November 1965 was granted a permit to install a 6 inch 3 mile gas line to deliver gas from its Esther and Antelope Fields to Saskatchewan Power Corporation. The gas is delivered through about one half mile of Trunk Line's system. Licences to operate the respective lines were issued in December 1964 and November 1966.

(9) Westcoast Company (Alberta) Limited constructed 39 miles of gas line varying in sizes from 6 inches to 26 inches to gather gas from the Pouce Coupe, Pouce Coupe South, Braeburn and Gordondale Fields for delivery to Westcoast Transmission Company Limited and Peace River Transmission Company Limited

for removal from the Province. Approval for the construction of these lines was given in 1956 by the Department of Highways who at that time administered The Pipe Line Act.

(1) Views of McCulloch

McCulloch did not comment on the role of Trunk Line. McCulloch submitted that its proposed gas line was of a high risk nature and the risk would be assumed completely by McCulloch. The scheme would result in additional money being invested in the Province and would provide incentive for further exploration of gas in the area. McCulloch stated that if both applications were granted it would proceed with the construction of its system but it considered that the total area would be better served if only one application were approved.

(2) Views of Trunk Line

Trunk Line stated that to date the role of Trunk Line has been to provide the transmission service for natural gas developed and produced in Alberta, primarily for delivery to markets outside the Province, but to some extent for markets within the Province. As a result of the requirements in permits issued for removal of gas from the Province, Trunk Line has installed approximately 330 taps for individual residences and 109 taps for towns, villages and co-operative associations. It expressed the opinion that while there is merit in the concept of restricting its role to general transmission services to all buyers and shippers throughout the Province and not actively to buy and resell gas, Trunk Line is prepared to buy and sell gas in this and other cases. Such service would unblock marketing tie ups, supply local consumers and in this instance keep the Wainwright system economically viable. Trunk Line said that actual experience had indicated that a main line gas transmission service would provide better economics to both the producer and the Province as a whole. It stated that a main Trunk-Line system in an area produces a competitive situation for gas purchases in the field and contended that experience shows that lines owned by individual gas buyers are not usually used competitively by several buyers but "become a gas supply tool of the individual buyer who owns the pipe line". It stated its system would enhance exploration incentives in the area by enhancing competitive buying and would have the advantage to the public of Alberta "through recognition of ownership and the locale of the equity ownership of the company". Trunk Line stated that the jurisdiction and authority of the Province would be weakened by the proposal suggested by McCulloch. It suggested

that there would be some loss of position in the closeness of the Alberta authority if the control of the gas gathering system was not in the hands of the Province.

Trunk Line stated that serious inefficiencies would result if both gas lines were constructed and suggested that only one application should be granted.

(4) Views of the Board

The Board accepts the view of the applicants that only one of the competing applications should be granted.

The Board continues to believe as it did in 1953 that in general "integrated gathering facilities based on a Provincially controlled Trunk-Line system operating as a common carrier would facilitate conservation, provide for flexibility of development, give maximum protection to the Province and be in the mutual interest of consumers, producers and transporters of natural gas". The Board notes that The Alberta Gas Trunk Line Company Act does not provide Trunk Line with exclusive rights for the transmission of gas in the Province, although permits issued by the Board under The Gas Resources Preservation Act for the removal of gas from the Province require that all gas to be removed be delivered through the facilities of Trunk Line. The Board believes that Trunk Line has provided generally good service to producers, and purchasers of gas. Many small communities and individual consumers have been provided with gas service because of the existence of the Trunk Line system. On the other hand, the situation disclosed by the present applications indicates that Trunk Line has not been as aggressive as perhaps it should have been in seeking out opportunities to provide service to Alberta communities and farms.

The Board has compared the McCulloch proposal with the other gas gathering systems referred to previously in this section. The Board notes that in each of the other cases the gathering line is owned by the producer whose gas is being gathered whereas in the present instance McCulloch would purchase the gas from the producer, and after transporting it to the delivery point, sell the gas to TransCanada. An additional difference between the McCulloch proposal and the several producer gathering lines is that as far as the Board can ascertain, Trunk Line did not offer to provide gathering services in the areas involved, whereas in the Wainwright-Chauvin Area, Trunk Line has made a specific application to construct and operate facilities. Except for these differences the cases are relatively comparable.

As discussed in previous sections the Board believes that each applicant could effectively serve the needs of the producers

and consumers in the area. The Board appreciates that service is now being offered by Trunk Line largely as a result of the initiative of McCulloch. Nevertheless the Board recognizes that Trunk Line is now prepared to provide the service, and that it is a service for which Trunk Line was established. In the absence of evidence that the McCulloch proposal would offer a decided advantage to the producers or the consumers in the Wainwright-Chauvin Area the Board believes that it is in the best interests of the Province to grant the Trunk Line application.

Decision

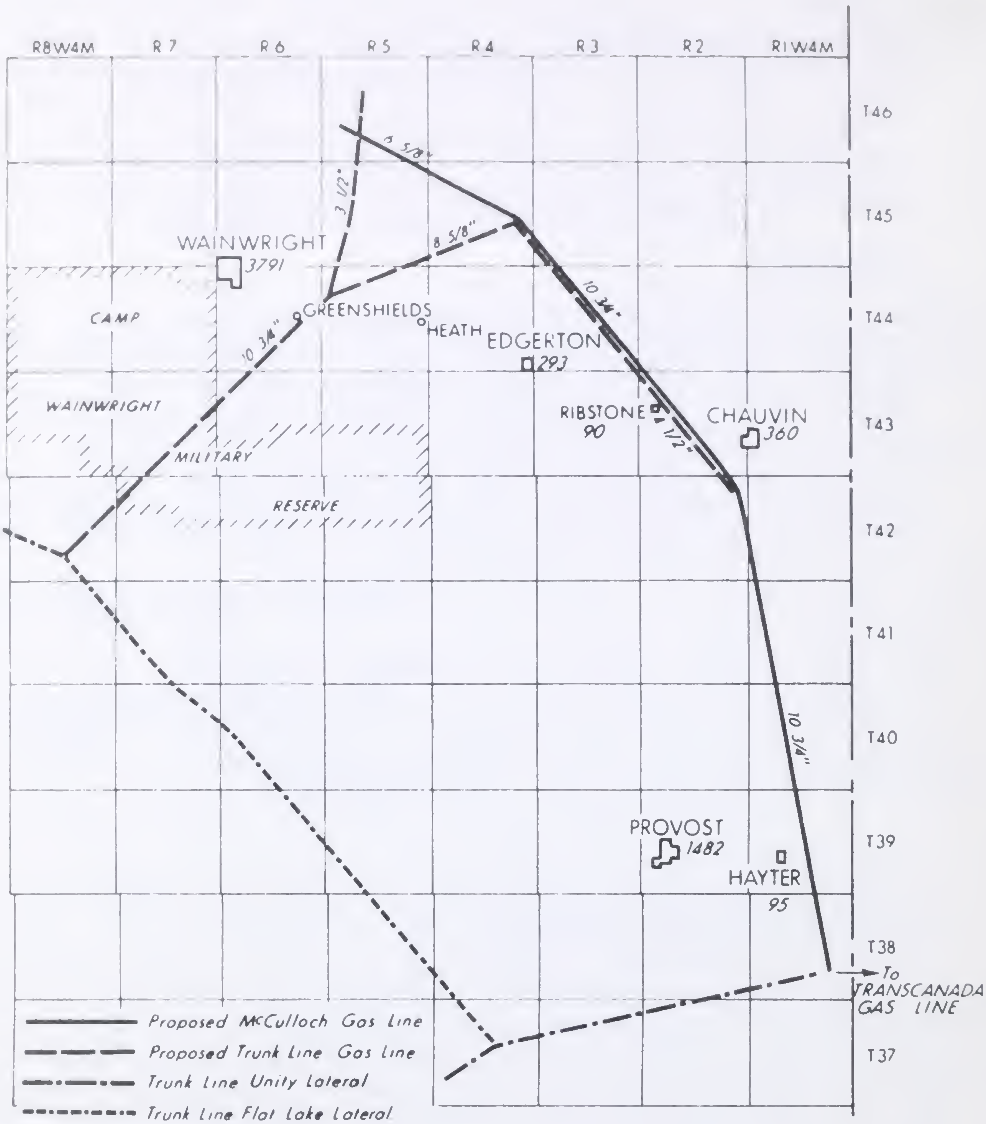
The Board grants the application of Trunk Line for a permit to construct a gas line in the Wainwright-Chauvin Area. The application by McCulloch for a permit to construct a gas line in the Wainwright-Chauvin Area is denied. Permit No. 12949 authorizing Trunk Line to construct a gas line is being issued concurrently with this decision report. It includes a provision for the commencement of construction of the gas line by July 1, 1972 and for commencement of service not later than September 1, 1972.

ENERGY RESOURCES CONSERVATION BOAR

D R Craig

for G. W. Govier
Chairman

DATED at Calgary, Alberta
March 20, 1972



Note Figures under town names denote 1971 population.

PROPOSED GAS LINES

WAINWRIGHT - CHAUVIN AREA

FIGURE 1

DECISION 72-2

ENERGY RESOURCES CONSERVATION BOARD
CALGARY, ALBERTA

ATTACHMENT I TO DECISION NO. 72-2

Excerpts from the Board Report Entitled:

"The Petroleum and Natural Gas Conservation
Board Report to the Lieutenant Governor in
Council with respect to the Applications
under The Gas Resources Preservation Act of:
Canadian-Montana Pipe Line Company.
Trans-Canada Pipe Lines Limited, Trans-Canada
Grid of Alberta Ltd., and Canadian Delhi Oil Ltd.
Western Pipe Lines. November 24, 1953."

VI.—IN THE MATTER OF THE EFFICIENT DEVELOPMENT AND UTILIZATION OF THE GAS RESOURCES OF THE PROVINCE WITH RESPECT BOTH TO THE PRESENT AND FUTURE REQUIREMENTS OF THE PROVINCE AND THE MARKETS OUTSIDE THE PROVINCE

The Board believes that efficient development gathering and utilization of the gas resources of the Province would be promoted by the institution of a "Trunk-Line" system operating within the Province as a common carrier under full Provincial jurisdiction and control.

Such a system would not, at the present time, extend either to the Peace River area or to the Pakowki Lake area, but it would facilitate interconnection of the bulk of the other reserves of the Province with the main market areas of the Province and with the "gate" on the Provincial border to markets east of Alberta. The system proposed by the Board is a modification of proposals submitted by Alberta Inter-Field Gas Lines Limited. Its essential facilities, as now anticipated, would include a line of some 24 inches in diameter extending from the Homeglen-Rimbey field south to Calgary, and then east by south-easterly to near Arrowwood from where a line of some 30 inches in diameter would extend eastward to the Alberta-Saskatchewan border. An early extension of this line from Homeglen-Rimbey to the Edmonton area is contemplated. The "Trunk-Line" system would accept for delivery either to Alberta markets or to markets east of Alberta gas delivered to it by other lines owned and operated by producers, the local utility companies, export companies or by the "Trunk-Line" system itself. Such a system, in the opinion of the Board, would promote conservation and efficient utilization of the gas resources, flexibility of development, joint and efficient use of all facilities and the sharing of markets. Moreover, as so strongly represented by Alberta Inter-Field Gas Lines Limited, it would strengthen the control of gas within the Province by Provincial authorities. Further details of the operation of the system and its advantages are discussed in Appendix F. Figure F-1 illustrates the general route of the "Trunk-Line" in relation to the location and magnitude of the reserves and the location of the markets.

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APPENDIX F

IN THE MATTER OF THE EFFICIENT DEVELOPMENT AND UTILIZATION OF THE GAS RESERVES OF THE PROVINCE WITH RESPECT BOTH TO THE PRESENT AND FUTURE REQUIREMENTS OF THE PROVINCE AND THE MARKETS OUTSIDE THE PROVINCE

The Board has given considerable thought to the manner in which the gas reserves of the Province could be best developed and utilized to supply and protect the requirements of the Province and to serve outside markets. From its interpretation of the testimony presented at the hearings together with its own studies on reserves, trends, Provincial requirements and deliverability, the Board is convinced that whatever plan of development and utilization is adopted, that plan should promote:

(a) conservation and the efficient utilization of the gas resources of the Province;

(b) flexibility of development, to the end that any necessary diversion of gas from Provincial to export use—or vice versa—is possible;

(c) access of consumers in the Province to that gas which can be delivered most economically to them;

(d) control of gas within the Province by Provincial authorities;

(e) market sharing or the operation of a market proration plan; and

(f) joint and efficient use of field, plant, pipeline, and other facilities for the mutual benefit of consumers, producers, and distributors.

These convictions indicate to the Board the need for close integration—where economically feasible—between existing and new pipeline systems within the Province. The Board, in other words, is now convinced of the desirability of reasonable interconnection of fields with the pipeline systems serving both the Alberta and the export markets. The degree to which this should be done and the best manner for its accomplishment are matters dependent upon a balance between the cost of interconnection and the benefits to be derived.

Any sound plan for the interconnection of the diverse fields with both internal and external markets must be conceived in the light of:

(a) the location, magnitude and deliverability characteristics of the gas reserves (for discussion on the importance of deliverability characteristics see the 1951 and the 1952 reports of the Board and Appendix D of this report);

(b) the location of areas of the Province most favorable for future gas discoveries;

(c) the location, magnitude and load factor characteristics of the markets within the Province; and

(d) the location (s) on the Provincial border of the "gate (s)" to markets outside the Province and the magnitude and load factor characteristics of those markets.

The importance and role of the above factors on the design of an interconnection scheme is almost self evident. Included within item (a) would be the important matter of conservation of unavoidably produced oil field gas through the assurance of market outlets for it. Also under this category would be need for the provision of high load factor markets for processed gas produced from wet gas fields such as Pincher Creek.

With its thinking guided by these general concepts, the Board has reviewed the details of the design of the various gathering systems advocated by the applicants, Alberta Inter-Field Gas Lines Ltd. and the utility companies.

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Trunk-Line System

The Board is of the view that the advantages and the disadvantages of the several schemes proposed may be best reconciled through the creation of a Trunk-Line system operating in conjunction with field lateral lines and acting as a common carrier under complete Provincial jurisdiction. The Board believes that the system itself need only include the main or trunk-lines which appear in any event to be necessary to serve the Province and export markets to the east. The Trunk-Line would extend from the Edmonton area to Calgary (as proposed by the utility companies) and then easterly to the export "gate" at the Saskatchewan border. Lateral lines from the fields could be built by the producers, the utility companies, the export companies or by the Trunk-Line system itself.

The general route of the Trunk-Line is shown schematically in Figure F-1. The line is routed reasonably directly except for slight deflections towards the larger reserves. Preliminary design of the trunk line to suit the anticipated volumes in the year 1965 indicates that the Edmonton area—Calgary portion would have an equivalent diameter of about 24 inches and would cost 10 or 11 million dollars while the portion east of Calgary would have an equivalent diameter of about 30 inches and would cost some 16 to 17 million dollars.

The Board has estimated the average transmission costs over the period 1956-1965 inclusive, as follows:

(a) Average gathering costs from fields to the Trunk-Line—some 1.4 MCF

(b) Average Trunk-Line costs for delivery to the eastern export gate—some 3.2 MCF

(c) Total average transport costs from fields to the eastern export gate—some 4.6 MCF.

These transmission costs are preliminary figures but believed to be within 10 or 15 per cent of what the actual costs would be.

The line could operate either as a common carrier or as both a common carrier and a common purchaser. Operation as a common carrier would permit full realization of pipeline economics through planned joint use of the facilities. At the same time it would leave to the producer and the local or export purchaser the matter of negotiation of the terms of the sale and purchase—subject to Provincial regulations.

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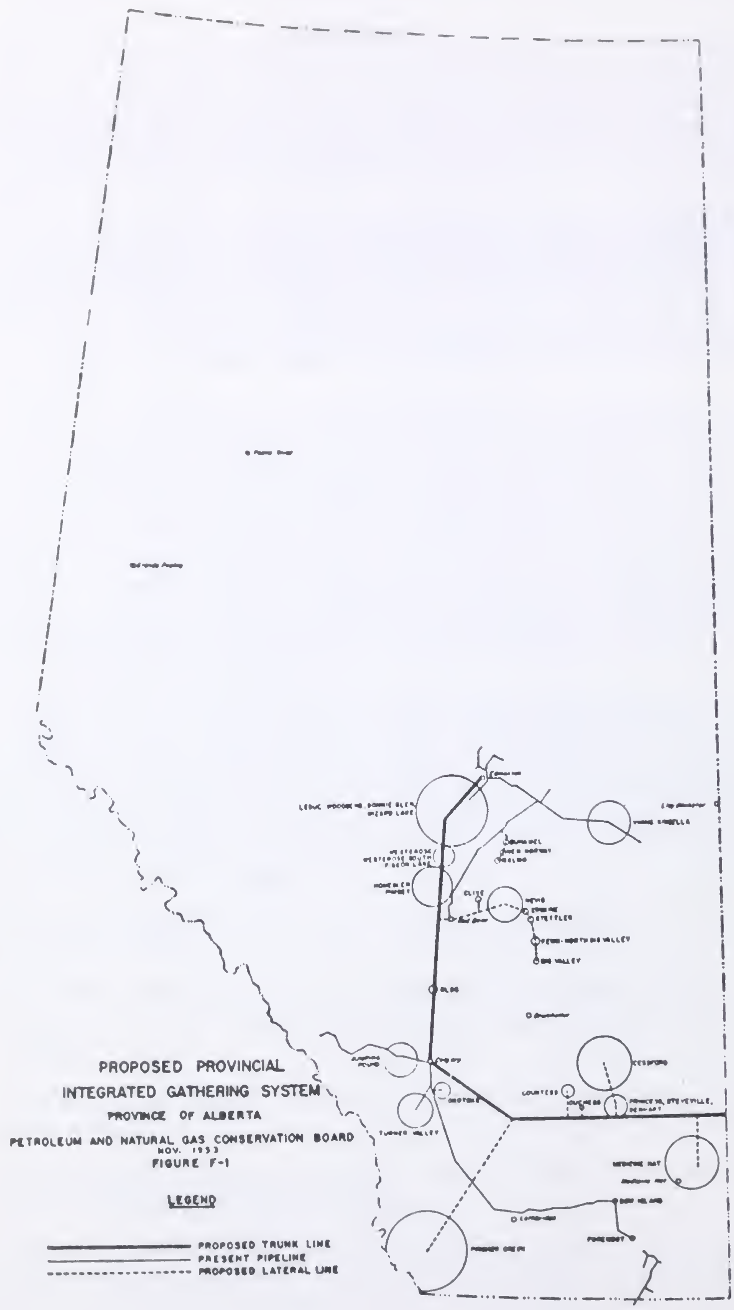
Conclusion

The Board concludes that integrated gathering facilities based upon a Provincially controlled Trunk-Line system operating as a common carrier would facilitate conservation, provide for flexibility of development, give maximum protection to the Province and be in the mutual interest of consumers, producers and transporters of natural gas. Such a system would allow dry gas fields better to share in the higher load factors of an export market as well as permitting higher load factors for wet gas fields and their associated plants. An integrated plan based on the Trunk-Line system could deliver gas at the eastern border of the Province in quantities and at rates which, for all practical purposes, would meet the requirements of either Trans-Canada Pipe Lines Limited, et al, or Western Pipe Lines.


PROPOSED PROVINCIAL
INTEGRATED GATHERING SYSTEM
PROVINCE OF ALBERTA
PETROLEUM AND NATURAL GAS CONSERVATION BOARD
NOV. 1953
FIGURE F-1
LEGEND
PROPOSED TRUNK LINE
PRESENT PIPELINE
PROPOSED LATERAL LINE
CLIVE
STETTLER
BIG VALLEY
COUNTESS
CESSFORD
MEDICINE HAT
TURNER VALLEY
PINCHER CREEK
FOREMOST

ENERGY RESOURCES CONSERVATION BOARD

Decision 72-3
Proceeding No. 6000

ANNUAL RESERVES AND PRODUCTIVE CAPACITY

HEARING

A hearing was held by examiners appointed by the Board for the purpose of hearing representations respecting the recoverable reserves of crude oil in those pools listed in Table I. In addition, the examiners heard productive capacity presentations for those pools listed in Table III.

The hearing was conducted by N. A. Strom, P. Eng.; J. R. Pow, P. Eng.; and H. J. Webber, P. Eng. on February 14 and 15, 1972. Due to illness, Mr. Pow was unable to participate in the decisions.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Amoco Canada Petroleum Company Ltd.	D. C. Smith, P. Eng. I. M. Fieldman, E.I.T.	Amoco
Atlantic Richfield Canada Ltd.	J. R. Bherer, P. Eng. D. L. Bowman, P. Eng. J. Anderson	ARCO
Canadian Superior Oil Ltd.	M. T. Alexandre, P. Eng.	Canadian Superior
Gulf Oil Canada Limited	M. J. Melnyk, P. Eng.	Gulf
Home Oil Company Limited	J. R. Sears, P. Eng.	Home
Hudson's Bay Oil and Gas Company Limited	S. R. Chakravorty, P. Eng. M. B. Field R. W. Hoover R. L. Keto K. R. Kirkness D. J. McNeil	Hudson's Bay
Imperial Oil Limited	W. B. Baker, P. Eng. J. W. Pollock, P. Eng. B. T. Reilly, P. Eng.	Imperial

APPEARANCES (Cont'd)

	Represented by	Abbreviation Used in Report
Mobil Oil Canada, Ltd.	J. S. Ambler, P. Geol. S. K. Bhatia, P. Eng. G. C. M. Derbowka, P. Eng. G. M. Leavitt R. A. Slotboom, P. Eng.	Mobil
Samedan Oil of Canada, Inc.	F. W. Kelly G. J. McLeod	Samedan
Shell Canada Limited	J. A. Irvine, P. Eng. R. W. Labelle, P. Eng. W. J. Longstaff	Shell
Texaco Exploration Canada Ltd.	D. A. Nikiforuk, P. Eng. P. A. Workun	Texex
Webb Resources Inc.	F. M. Wormsbecker, P. Eng.	Webb
Energy Resources Conservation Board Staff	G. H. Stafford, P. Geol. B. R. O'Brien, P. Geol. M. J. Vrskovy, P. Geol. R. A. Purvis, P. Eng. C. C. Fortems, P. Eng.	Board Staff

SUBMISSIONS

Included in each submission was the Board's O-38 form, providing a listing of the reservoir factors pertinent to the establishment of ultimate reserves. Only four of the submissions were based on pool extensions while eleven submissions were a re-evaluation of the recovery factor, with a majority of these based on performance as interpreted from oil-water interface advance. One submission for increased oil-in-place in a relatively large pool involved a detailed analysis of pressure/production data and the use of the linear material balance approach.

MER submissions were given increased attention in view of the trend toward accelerated production and reduced proration constraints for many oil pools.

FINDINGS OF THE EXAMINERS

Ultimate Reserves

The findings of the examiners with respect to the setting of recoverable reserves are tabulated in Table I. Comparisons of oil-in-place and recoverable oil reserves as proposed by the operator and as recommended by the examiners are shown in Table II. As a rule, the examiners determined that there were only a few specific points of contention involved in each submission. These points are discussed in detail in the following text.

Sundre Rundle A Pool

Hudson's Bay proposed increasing the assigned oil-in-place for the Sundre Rundle A Pool by 2,185 MSTB based on a porosity footage map interpretation and assignment of 248 porosity feet to a well recently drilled in LS 1-35-33-5 W5M. The examiners generally agree with Hudson's Bay's interpretation except that they would use a slightly higher log cut-off of 51 microseconds giving a net pay of 44.8 feet rather than the 49.6 feet proposed by Hudson's Bay. Also the examiners believe that a water saturation fraction of 0.22 is more appropriate than the field average value of 0.13 proposed by Hudson's Bay on the basis that the porosity at the 1-35 well is only about 0.051 as compared to a pool average value of 0.105. Using their adopted reservoir factors, the examiners calculate an oil-in-place increment of 1580 MSTB.

Hudson's Bay proposed applying the pool average primary recovery factor of 0.25 to the additional oil-in-place proven up by the 1-35 well. The examiners believe that the comparatively low porosity and permeability existing at the 1-35 well will result in below average performance and on this basis recommend assigning a primary recovery factor of 0.15 for that part of the pool. This results in a reserves increment of 237 MSTB for the area.

Meekwap D-2 A Pool

Due to the drilling of a number of delineating wells since the February, 1971 reserves review of the Meekwap D-2A Pool, Samedan's estimate of rock volume has been reduced from some 273,000 acre-feet to some 156,000 acre-feet. This latter value was determined by using arbitrary cut-offs of 2% and 1 md in assigning net pays to individual wells. The examiners have employed cut-offs of 3% and 1 md and thereby determine a slightly lower net pay for some wells than those submitted by Samedan. Also, the examiners believe that Samedan has been optimistic in its placement of the zero isopach, considering the available well control. Having regard for these effects, the examiners recommend assigning a rock volume of 135,000 acre-feet.

The porosity, as proposed by Samedan, was derived from seven cored wells and was weighted volumetrically for dolomite and limestone facies. The examiners believe that data from the twelve cored wells should be utilized, giving a porosity of 0.085. The need to weight porosity according to facies type was considered and rejected as having an insignificant effect.

The recovery factor of 0.292 as proposed by the operator, a volumetrically weighted value for facies type, is based on assigning 0.20 and 0.30 to the limestone and dolomite facies, respectively. Utilizing limited pressure data and the generalized material balance equation, the examiners observe that the pool is benefiting from a partial water drive index in the order of 0.30 to 0.50. Assuming an attic loss of 10 feet and a sandwich loss of an additional 10 feet plus the presence of a partial water drive, a recovery factor of 0.30 is estimated. The examiners adopt this value. Should performance indicate that the water drive is stronger than presently indicated, an upward adjustment in recovery factor may be warranted.

Sturgeon Lake South D-2 A Pool

Hudson's Bay estimated the initial oil-in-place for the Sturgeon Lake South D-2A Pool at some 5,200 MSTB. The examiners agree with the reservoir parameters making up this value with the exception of the shrinkage factor. The operator's number of 0.63 is based on a PVT sample from the D-3 corrected to the bubble point pressure of the D-2, and an initial solution gas-oil ratio (GOR) of some 1,070 SCF/STB. In contrast, initial production data suggests the GOR was in the order of 800 to 900 SCF/STB. A shrinkage factor of 0.68, corresponding to a GOR of 820 SCF/STB is adopted by the examiners, thus yielding an initial oil-in-place of 5,560 MSTB.

Utilizing waterflood susceptibility test data from the Joffre D-2 Pool, which has reservoir properties similar to those of Sturgeon Lake South D-2 Pool, the operator estimated a flushing efficiency of 0.6579. Combining this with an arbitrary 0.80 volumetric sweep efficiency and a 10 foot sandwich loss at the original gas-oil interface, a recovery factor of 0.413 was calculated. Considering the horizontal and vertical permeability, the water drive index, and the heterogeneous nature of this pool, the examiners believe that coning will probably be a serious problem in the latter stages of depletion. On this basis the examiners have assigned a sandwich loss of 25 feet and this leads to a recovery factor of 0.30.

West Drumheller D-2 A Pool

Gulf submitted a revised volumetric interpretation of oil-in-place for the West Drumheller D-2A Pool incorporating the recent westward extension to the pool. Gulf estimated the oil zone rock volume to be some 211,000 acre-feet with the original oil-water interface at 2943 feet subsea and the original gas-oil interface at 2860 feet subsea. The examiners agree with Gulf that an upward revision in oil zone rock volume is justified on the basis of the recent extension to the pool. The examiners find, however, that there is no new evidence to justify a change in the Board's previously established original oil-water interface of 2940 feet subsea and original gas-oil interface of 2870 feet subsea. On this basis, the examiners recommend assigning an original oil zone rock volume of 190,000 acre-feet, an upward revision of 10,000 acre-feet from the Board's previously assigned value. The The recommended oil-in-place is proportionately larger at 43,600 MSTB.

Gulf estimated a current average oil-water interface position at 2919 feet subsea from measurements at an interface observation well and by inference from knowledge of the completion intervals and production performance of producing wells. On this basis Gulf estimated the ultimate recovery efficiency will be 0.63 resulting in ultimate crude oil reserves of some 32,000 MSTB. The examiners agree with Gulf that the lone interface observation obtained thus far does not provide a reliable basis for estimating the rate or amount of advance of the oil-water interface. Also attempts to interpret the current oil-water interface position on the basis of production performance result in quite variable interface estimates. Assuming an error of ± 5 feet in the estimation of the current oil-water interface results in the recovery efficiency being estimated as low as 0.55 and as high as 0.73. The examiners recognize that with some 0.38 of the oil-in-place already recovered, there is good assurance that the recovery efficiency will exceed 0.60. On this basis, the examiners recommend that the existing assigned recovery factor of 0.63 continue to be assigned until more accurate information on the current oil-water and gas-oil interface positions becomes available.

Fenn Big-Valley D-3 A Pool

The examiners agree largely with the interpretation of oil-in-place submitted by Gulf. They also agree that performance (oil production compared to flushed zone volume) confirms that the flushing efficiency is about 0.78. The examiners are of the opinion that Gulf's recovery factor of 0.76 accounts for attic losses but does not allow for sandwich losses. After allowing for sandwich losses, the examiners estimate the recovery factor will be 0.70.

Innisfail D-3 Pool

Shell's reserves submission for the Innisfail D-3 Pool was primarily a re-evaluation of the recovery factor. For this purpose Shell provided an interpretation of the rock volume versus subsea depth based on a structure map and an average initial oil-water interface.

Four oil-water interface measurements taken during 1971 averaged 5465 feet subsea, the same elevation as was interpreted in last year's reserves submission for the pool. Shell's predicted a recovery factor of 0.70 incorporates the flushing efficiency as indicated by the currently interpreted oil-water interface and as modified by presence of an average residual free gas saturation of 0.045. In its evaluation, Shell assumed a maximum residual free gas saturation of 0.05, an amount equal to the maximum critical gas saturation as determined from gas-oil relative permeability tests on core samples from the pool. This value was said to be conservative having regard for data from other D-3 pools. Shell acknowledged that it had not attempted to confirm its views concerning the trapped gas saturation by observation of the gas-oil interface and related reservoir calculations.

By comparing the area-weighted oil-water interface measurements of 1970 and 1971, the examiners interpret an average rise of one foot over the year. Although this change is of about the same magnitude as the precision of the measuring device, it should not be ignored.

The examiners do not accept Shell's interpretation that residual oil saturation will be effectively reduced due to displacement by the release of gas from oil already by-passed by advancing water. The examiners believe it improbable that the trapped oil would be expelled from pores and caused to migrate upward through the water swept region to the remaining oil zone during the reservoir life. They recognize, however, that a free gas phase established and trapped in the oil leg before water invasion could directly reduce residual oil saturation. The examiners are concerned that the trapped gas benefit phenomenon has neither been shown to be operative in the laboratory using simulated displacement conditions nor demonstrated to be occurring in the pool. The examiners have determined that a recovery factor of 0.60 for the Innisfail D-3 Pool is appropriate on the evidence presently available, although they concede that a slightly higher recovery factor may eventually be proven.

Nevis D-3 E Pool

Webb estimated the oil-in-place in the single well, Nevis D-3 E Pool by a volumetric method using geophysical data to determine the reservoir extent and well data to determine the oil-water interface position, and rock and fluid properties. The examiners have reviewed the isochron interpretation and conclude that a very large error in reservoir volume could occur because of inadequacies in the control provided by the seismic data.

The examiners are of the opinion that a linear material balance approach[1] is a suitable method for estimating oil-in-place in this single well pool in view of the substantial pressure decline (370 psi) that has occurred. Using this approach, the examiners conclude that the oil-in-place is about 8,000 MSTB, slightly less than that proposed by Webb.

The examiners accept the recovery factor of 0.5253 estimated by Webb, but believe that it should be rounded to 0.50 in view of the limited production history of the pool.

Redwater D-3 Pool

Imperial requested that the recoverable reserves of the Redwater D-3 Pool be increased from 780,000 MSTB to 848,000 MSTB. The request was based on oil-water contact measurements from ten observation wells used to interpret the position of the oil-water interface and flushed zone rock volume at September 1971. Identical flushing efficiency and recovery factors of 0.664.were obtained using this information and supportive assumptions. No change was made in any of the other reservoir parameters from those previously requested at the reserves hearing in February 1965. These parameters were all essentially based on the 1953 report by the Redwater Working Committee entitled "Structural and Porosity Characteristics of the Redwater Field".

Imperial interpreted the current interface as being tilted from 1230 feet subsea in the back-reef to 1170 feet subsea in the fore-reef, with a level portion at 1167 feet subsea covering approximately 10 sections in the north-central part of the pool. Imperial stated that the westerly area of interfacial tilt, which was interpreted as extending across the whole pool in the 1965 submission, would eventually disappear

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(1) The Material Balance as an Equation of a Straight Line. D. Havlena and A. S. Odeh, Journal of Petroleum Technology, August, 1963, p. 896.

and oil would ultimately be displaced by an advancing level interface toward a number of small crestal closures on the reef. Imperial submitted a generalized coning prediction for crestal wells which showed that sandwich losses in the crestal areas due to coning would be equivalent to only a couple of feet. It concluded that ultimate recovery efficiency would be very nearly the same as the presently determined flushing efficiency.

Texex intervened, submitting that Imperial had excluded several measurements taken in September, 1971 from its interpretation of the oil-water interface. Texex provided a contour map of the current oil-water interface based on all measurements. The resulting interpretation differs from that submitted by Imperial mainly in that it shows a tilted interface across much of the pool. Texex noted that the revised contouring indicated that a significantly larger volume has been invaded than that calculated by Imperial. Using a residual oil saturation of 0.27 as submitted by Imperial in 1965 and incorporating a pool-wide 5 foot sandwich loss, Texex then proposed an ultimate recovery factor of 0.608.

Imperial disagreed with the Texex interpretation of flushed rock volume in that it involved unqualified use of all interface measurements. In its rebuttal Imperial explained why it had rejected the additional interface observations used by Texex.

The examiners are in agreement with Imperial that the porosity distribution interpretation provided by the Redwater Working Committee (1953) is an acceptable basis for determining pore volume distribution. The examiners draw attention to the interpretation, insofar as the determination of the original and current positions of the oil-water interfaces in relation to the high porosity regions can have an important bearing on the flushing efficiency estimates.

The examiners note that the Board's presently assigned rock volume is some 54,000 acre-feet greater than that submitted by Imperial, and have determined that of this difference, some 34,000 acre-feet is at the reef flanks not included in the building block volume submitted by Imperial and 20,000 acre-feet is at the pool base owing to the original oil-water interface being placed one foot lower than that used by Imperial.

Concerning the current interface position, the examiners note that the main point of contention is whether the interface is level or tilted in the north-central part of the pool. The examiners believe that some of the interface measurements rejected by Imperial and used by Texex in the area of concern should be given at least partial weight in

the interpretation. On this basis, the examiners have estimated that, proceeding from west to east, the interface slopes upward and levels off at about 1150 feet subsea and then drops to about 1170 feet subsea in the stratified fore-reef. In a corresponding but larger plateau area, Imperial interprets the interface to be level at 1167 feet subsea.

The examiners, having accepted the same porosity and initial oil saturation values as used by Imperial, have obtained a flushed zone rock volume nearly 7 per cent larger than the value of 1,739,000 acre-feet suggested by Imperial. The examiners recognize that small but significant variations of interpretation, including the one foot discrepancy in original oil-water interface, the reef flank effect and the principles used in contouring the current interface, would account for half the difference. The remainder, estimated to be about 60,000 acre-feet, arises from the differences in interpretation of the interface level in the north-central part of the pool and in this respect the examiners are not prepared to accept Imperial's interpretation. On the foregoing basis, the examiners have concluded that the flushing efficiency is about 0.63.

The examiners believe that performance of the pool does not support Imperial's contention that "oil... migrates from the low areas to the wells in structural highs due to the excellent reservoir continuity." The examiners believe that some allowance for sandwich and conformance losses must be made, especially in the back-reef area. After providing for such losses, the examiners conclude that a recovery factor of 62% is appropriate and should be adopted on the basis of performance to this time.

St. Albert Big Lake D-3 A Pool

Imperial proposed a recovery factor of 0.694 on the basis of observed oil-water contact advance, a continued strong water drive and a sandwich loss of 15 feet at the crest of the pool. In support of its evaluation, Imperial submitted a structure contour map, a hydrocarbon volume versus depth curve generated from the map, a graph of measured oil-water contact versus time and other data. The examiners agree with Imperial's interpretation of the current oil-water contact position. The examiners believe that the structural contours on Imperial's map have been too closely stacked below the 2600 feet subsea contour. This has the effect of giving an optimistic flushing efficiency and on this basis, the examiners regard Imperial's estimated flushing efficiency of 0.76 as being too high. The examiners also believe that Imperial's assumption of a contunued 100 percent water drive may be incorrect in view of the recent pressure decline in the pool. Using a flushing efficiency of 0.70, a sandwich loss of 15 feet, and a nominal allowance of 0.05 to account for the lower recovery associated with a limited water drive, the examiners estimated a recovery factor of 0.6[illegible].

Stettler D-3 B Pool

Gulf proposed that the recovery factor of the Stettler D-3 B Pool be increased from 0.50 to 0.62. It based its recommendation on an estimate of flushing efficiency developed from an interpretation of the current oil-water interface position and an assumption of a nominal attic loss. The examiners are basically in agreement with the Gulf recommendation but believe that the recovery factor should be rounded to 0.60 in view of the inherent inaccuracies in the data and evaluation method.

Stettler South D-3 Pool

Gulf recommended revising the assigned oil-in-place for the Stettler South D-3 Pool upward to a value of 2,557 MSTB. The examiners are largely in agreement with the proposed changes in rock volume and porosity which yield the new value.

Gulf used performance of the well in LS 6-27-37-20 W4M as of April 1967, to position the oil-water interface at 2619 feet subsea and evaluate a flushing efficiency of 0.65 and a recovery factor of 0.60. The examiners accept Gulf's approach but have used subsequent performance data to estimate the interface position at the 1971 year-end at 2616 feet subsea. This generates a flushing efficiency of 0.57. Assuming a five foot sandwich loss, the examiners estimate a recovery factor of 0.55.

Sturgeon Lake South D-3 Pool

Utilizing 15 years of history and the linear material balance technique, Hudson's Bay has evaluated the initial oil-in-place of the Sturgeon Lake South D-3 Pool at 287,500 MSTB which is in close agreement with the 283,800 MSTB requested in the 1966 submission. The examiners note that the confirmation of previously estimated oil-in-place using the material balance reflects the thoroughness with which the basic reservoir data was analyzed. The examiners are therefore satisfied that the results are fully valid and recommend assigning an initial oil-in-place of 285,000 MSTB for the pool.

Carson Creek North Beaverhill Lake A Pool

Mobil submitted a volumetric re-evaluation of the oil-in-place in the Carson Creek North Beaverhill Lake A Pool incorporating the recent northwest extension of the pool. Hydrocarbon pore volume maps, mechanically drawn, were employed.

The examiners agree with Mobil's volumetric interpretation except that they believe contours on the southern edge of the pool should be separated more and contours on the northwestern edge should be moved in closer. Also, the examiners believe that previously established porosity and water saturation values are suitable. On these bases, the examiners recommend an oil-in-place value of 86,300 MSTB.

Carson Creek North Beaverhill Lake B Pool

Similarly, as for the Carson Creek North Beaverhill Lake A Pool, Mobil submitted a full volumetric re-appraisal for the B Pool. The examiners find the interpretation generally acceptable but believe the rock volume is slightly less on the northwest side and in some crestal areas. The examiners recommend assigning a rock volume of 770,000 acre-feet, up from the previous value of 706,000 but less than the 808,000 proposed by Mobil. All other reservoir factors are unchanged.

Rainbow Keg River II Pool

Mobil recommended assigning an oil-in-place for the Rainbow Keg River II Pool of 27,574 MSTB based on history matching techniques and as supported by a volumetric estimate of 31,680 MSTB.

Communication between the Rainbow Keg River II Pool and JJ Pool through the aquifer plus the sensitivity of the history match to assigned aquifer volumes complicates the history matching for those pools. The examiners note that, while Mobil estimated the aquifer size associated with the volumetric oil-in-place at 27,960 MRB, Mobil employed an aquifer size of only 9,361 MRB in the reservoir simulation. The examiners believe that an equally valid history match of the II Pool could be obtained by making a nominal reduction in the oil-in-place and using a more realistic aquifer size. Using such an approach, Board staff history matching gives an oil-in-place of 21,000 MSTB. Having regard for all the evidence, the examiners have concluded that the original oil-in-place is about 25,000 MSTB.

After establishing a satisfactory history match, Mobil made a prediction run to abandonment of the reservoir. Using a residual oil saturation of 0.30 and an effective sandwich loss of two to three feet, Mobil determined the water flood recovery factor of 0.667. The 0.30 residual oil saturation, which corresponds to a flushing efficiency of 0.667, was said by Mobil to be in agreement with the flushing efficiency estimated from oil-water contact observations at the well in LS 6-6-109-6 W6M and a hydrocarbon pore volume-depth curve.

The examiners consider it premature to accept the initial interface measurement as a basis to change the Board's current approach of assigning a residual oil saturation of 0.35 for water flooding of Keg River pools. The examiners recognize, however, that a history of contact measurements will in future be of considerable value for determining ultimate reserves. Using a sandwich loss of 20 feet, a residual oil saturation of 0.35 and a conformance factor of 0.95, the examiners calculate a recovery factor of 0.58 for the water flood area. The recommended recovery factor for the primary area is revised to 0.50 to reflect improved conformance.

Rainbow Keg River JJ Pool

Mobil proposed an oil-in-place value of 19,591 MSTB for the JJ Pool as determined from a simplified two dimensional model history match and as supported by a volumetric estimate of 16,380 MSTB.

The examiners find that the isochron values provided in support of Mobil's volumetric estimate could lead to a range of oil-in-place values generally much lower than that submitted by Mobil.

A volumetrically determined aquifer size of 21,096 MRB was employed by Mobil in obtaining the history match. The examiners believe that pressure measurements throughout this area of the Rainbow Field indicate a common aquifer is connected to several pools including the JJ Pool. The interpreted "salt edge" which Mobil contends rules out communication with a regional aquifer, is believed by the examiners to have been deposited on the Keg River in the inter-reef regions and does not necessarily assure isolation of the II Pool and JJ Pool from others. Using regional aquifer effects, Board staff history matching runs show that the oil-in-place for the JJ Pool may be as low as 8,000 MSTB. After considering all the evidence, the examiners recommend adopting an oil-in-place of 13,000 MSTB.

A recovery factor of 0.641 was predicted by Mobil for the JJ Pool using a residual oil saturation of 0.30 and a effective sandwich loss of two to three feet. Using a sandwich loss of 20 feet, a conformance factor of 0.90, and a residual oil saturation of 0.35, the examiners estimate a recovery factor of 0.51 under waterflooding.

Productive Capacity

Maximum efficient reservoir capacity (MER) submissions have been requested by the Board for a number of years. This information is used to prepare statistics and make rate forecasts which are essential for efficient planning by industry and government.

The peak value of MER Capacity (Peak MER) is defined as the peak value of the maximum production rate of a pool which could be developed economically and without detriment to ultimate recovery, assuming an unlimited market and the current crude oil price structure. Remaining reserves of the pool, economics of drilling and equipping additional wells, water and gas coning affects, natural limitations of the reservoir, and the economics of expanding enhanced recovery and gas conservation systems must be taken into consideration when estimating the peak MER.

An important assumption is that of the date on which unlimited market occurs. For this review, the date was assumed to be January 1, 1972. In this respect, the peak MER estimates are hypothetical since, in fact, the market was not near unlimited status at January 1, 1972.

MER capacity submissions were considered for fourteen pools. Table III compares the currently recognized peak MER capacity estimates with those submitted operators, and those recommended by the examiners. Some of the peak MER capacities were decreased because of more detailed analyses by the operators and the Board staff. It should be recognized however, that there is a natural tendency for the peak MER capacity of a pool to decrease with time. The decrease may be caused by reduced reservoir potential or by reduced economic incentive to drill infill wells or install facilities to accelerate recovery of the remaining reserve.

The examiners have employed the Board staff approach, described below, and the PRL formula as references by which to assess the suitability of MER capacity estimates submitted by operators. The examiners regard their conclusions as first order approximations of MER capacity. They recognize that more accurate determination of the MER capacity for a single pool could involve months of careful study and extensive model studies, and even then may suffer from limitations in basic reservoir data.

Board Staff Approach

Because of the increased importance and utility of peak MER estimates, the Board staff gave increased consideration to them this year. It has been found useful to prepare a rate-cumulative production plot for each pool. These plots show the peak oil rates for each calendar year to date, rate limitations suggested by the PRL formula, and the operators' estimates of how the MER may be expected to change with cumulative production. In certain pools it has also been found appropriate to plot total fluid handling capacity, voidage balances, pressures and performance indices such as gas-oil ratio and water-oil ratio.

In pools where there is an advancing gas-oil or water-oil interface, an index of oil productive capacity is given by the sum of the remaining wellbore oil columns raised to various powers (Σh_i^n, i = summation index over all the wells in the pool capable of oil production). It is convenient to use this index of productive capacity in the form of a dimensionless parameter. The parameter ξ_n, is defined as the ratio of the sum of the remaining wellbore oil columns to the sum of the initial wellbore oil columns raised to various powers ($\xi_n = \Sigma h_i^n / (\Sigma h_i^n)_{\text{initial}}$). Thus in calculating ξ_2 the wellbore oil columns are squared. Consider for example the hypothetical reservoir shown in Figure 1. The reservoir is a spherical segment with 6 wells. The relationship between the upward movement of the oil-water interface and cumulative oil production is shown in Figure 2. Figure 2 also shows how the parameters ξ_1, $\xi_{1.5}$ and ξ_2 change with cumulative oil production. Generalized coning correlations usually show the critical coning rate to be proportional to the square of the oil column thickness. Thus in a homogeneous and isotropic reservoir the critical coning rate would be proportional to the parameter ξ_2. In a heterogeneous reservoir with horizontal shaly streaks, or other features which would reduce the vertical transmissibility, it would be reasonable to assume that the critical coning rate would be proportional to the sum of the remaining oil columns to a reduced power such as the parameter $\xi_{1.5}$. Finally, if Darcy's law controlled, the rate would simply be proportional to the sum of the remaining wellbore oil columns. It may be noted in Figure 2 that the parameter ξ_1 varies linearly with cumulative production. The linearity results from the assumption that porosity, connate water saturation and displacement efficiency remain constant.

Bellshill Lake Blairmore Pool

This pool has a very active bottom water drive and the present productive capacity has been severely restricted because of water coning. The unit operator, ARCO, has drilled twenty infill wells, and an additional twenty wells are proposed to reach the peak MER capacity of 8,600 BOPD. ARCO estimated that the peak MER could be attained in 1973 and would decline to 8,000 BOPD by 1980.

The examiners note that the presently estimated ultimate recovery of some 80,000 MSTB is particularly sensitive to operating expenses and overall economics. The examiners estimate the peak MER to be 8,000 BOPD, somewhat lower than that estimated by ARCO, primarily because the water-oil ratio of the recently completed infill wells are expected to increase significantly by 1973. The examiners estimate of the MER capacity at the economic limit is based on the proposed installation of high volume artificial lift equipment and centralized treating facilities having a gross fluid capacity of 90,000 barrels per day. Based on a limiting water-oil ratio of 20, the MER at the economic limit would be 4,500 BOPD.

Figure 3 shows the history of peak daily oil rates attained in each calendar year and the projection for the MER in future years. The operator's estimate of MER corresponds to a decline rate of approximately 1 per cent per year, while the examiner's estimate corresponds to 2 per cent per year. Both estimates of MER capacity are far below those given by the usual values of K in the PRL formula.

Clive D-2 A Pool

Pressure maintenance by water injection into the aquifer has recently been started in the Clive D-2 A Pool. The plan is to displace the oil-water interface upwards and to keep the gas-oil interface stationary as the pool is depleted. Gulf estimated the MER capacity of the existing wells to be 3,500 BOPD and that if the pool were produced at this rate the MER capacity would soon start to decline. Gulf estimated a peak MER capacity of 5,000 BOPD could be achieved by drilling 10 infill wells. It believed that the peak MER capacity could be sustained for up to 6 years by drilling an additional 15 wells.

The examiners agree with Gulf that the peak MER capacity is in the order of 5,000 BOPD and the examiners understand from a previous submission by Gulf that the lag time to reach this level would be about 2 years. However, the examiners differ with Gulf on the estimate of the point when the peak MER capacity will start to decline. The examiners estimated that decline would begin at about 8,500 MSTB cumulative production based on the assumption that the critical coning rate is proportional to the sum of the squares of the remaining oil columns in those wells which are not watered out.

The various estimates of MER capacity and the peak annual oil production rates to the present are shown in Figure 4. The decline in the parameter ξ_2 for the existing wells plus 10 infill wells, with cumulative production is also shown in Figure 4. The cumulative production

at which the examiners believe the peak MER will start to decline occurs when $\xi_2 = 0.5$. A constant percentage decline rate of 13.2 per cent per year starting at cumulative production of 8,500 MSTB would lead to prediction of the recognized ultimate reserve of 21,600 MSTB. The examiners assumed a linear decline in MER capacity with cumulative production since it is likely that the critical coning rates will be exceeded after the decline starts.

Figure 4 indicates that rates in excess of the PRL at $K = 9,000$ could be attained by drilling more infill wells to extend the peak MER capacity. The examiners appreciate that the start and rate of decline of MER capacity depends upon the number of infill wells that are drilled and also other possible limiting factors including capacity of the water injection system and fluid transmissibility of the reservoir. This type of projection assumes that the number of infill wells is the only limiting factor.

Clive D-3 A Pool

Pressure maintenance by bottom waterflooding has been initiated in the Clive D-3 A Pool. Gulf estimated the MER capacity of existing wells to be 8,500 BOPD. It estimated that a peak MER of 10,500 BOPD could be attained by drilling 10 infill wells and the peak MER could be sustained for three years by drilling an additional 15 infill wells. The lag time to achieve this peak MER would be about 2 years according to evidence previously submitted by Gulf.

The examiners are in general agreement with Gulf's estimate of peak MER capacity, the lag time to achieve it and the time interval this capacity could be maintained by infill drilling. The examiners estimate the peak MER capacity to be 10,000 BOPD followed by a decline rate of about 18 per cent per year starting at a cumulative production of 26,000 MSTB. These estimates of MER capacity are shown in Figure 5. The decline in the parameter ξ_2 for the existing wells plus 25 infill wells is also shown in Figure 5. The somewhat better reservoir properties of the D-3 A Pool as compared to the D-2 A Pool are reflected by the fact that $\xi_2 = 0.35$ at the projected start of the decline in the peak MER capacity.

Gilby Jurassic B Pool

A peripheral waterflood has been in operation in the Gilby Jurassic B Pool since 1967, and good pressure response has been achieved. The currently developed wellhead capacity is 4,133 BOPD. ARCO estimated that if an unlimited market existed at January 1, 1972, a peak MER capacity of 4,000 BOPD could be attained in 1973, and that the MER would decline to 3,000 BOPD by 1980. Figure 6 shows this MER forecast.

The examiners agree that the peak MER will be in the order of 4,000 BOPD, and that is is reasonable to expect that the peak MER could be sustained for approximately one year. The examiners recommend that ARCO's 4 per cent per year decline in MER for this pool be adopted. However, the examiners believe that additional production history may indicate a higher rate of MER decline. This belief is based in part upon the parameter ξ_2 shown in Figure 6. A value of K = 7,000 in PRL formula would not cause any restriction in rates for this pool.

Golden Spike D-3 A Pool

Approximately 67 per cent of the minimum solvent bank of 28,500 MRB has been injected in this pool and solvent injection is scheduled to be completed in 1976. Imperial's estimate of peak MER capacity was based on a stable miscible displacement rate calculation and overall project economics. With infill drilling of 13 wells, Imperial estimated that a peak MER capacity of 80,000 BOPD could be reached by 1974, and that the peak MER could be sustained for 2 years.

The examiners believe that the peak MER capacity will be limited initially be a maximum stable displacement rate and later by well coning rates. The examiners conclude that an appropriate peak MER would be 70,000 BOPD.

The various estimates of peak MER are shown on Figure 7. An estimate of the critical coning rates can be made from the parameter ξ_2. Two curves are presented in Figure 7, one curve for the existing wells, and a separate curve which considers an infill drilling program of 13 wells. Based on this preliminary analysis, the peak MER is expected to start to decline after some 180,000 MSTB have been recovered. In the event that no further drilling occurs, coning would be the limiting condition at all times and the peak MER would be in the order of 50,000 BOPD. The superior reservoir properties of this pool are reflected by the value of K required to give a PRL comparable to the peak MER.

Harmattan Elkton Rundle C Pool

The Harmattan Elkton Rundle C Pool has recovered 45 per cent of its recognized reserve of 58,300 MSTB and oil productivity has been reduced because of increasing gas production. The solution gas conservation facilities have recently been enlarged to process the increasing gas production in the oil leg. Canadian Superior estimated the MER capacity with the enlarged gas conservation facilities to be 8,000 BOPD. Canadian Superior also estimated that with another enlargement of gas conservation facilites, the peak MER capacity would be 12,000 BOPD and that this rate could be sustained for one year followed by a decline rate of approximately 20 per cent per year.

The examiners believe that the peak MER capacity in this pool is likely to remain at 8,000 BOPD as limited by presently installed field and gas processing facilities.

Figure 8 shows the various estimates of MER capacity and the peak annual oil rates from production history. It may be noted that with continued operation under the constraint of the original gas conservation facilities, a decline rate of some 5 per cent is indicated. A peak MER capacity of 8,000 BOPD followed by a decline rate of 10 per cent per year will recover the recognized crude oil reserve of 58,000 MSTB in approximately 28 years. This producing life is comparable with the projected life of operations in the gas cap. The peak MER capacity is far below that suggested by the usual values of K in the PRL formula.

Judy Creek Beaverhill Lake A Pool

Approximately 24 per cent of the recognized reserve of 364,000 MSTB has been recovered from the Judy Creek Beaverhill Lake A Pool. Reservoir pressure is being maintained primarily by a flank water injection scheme. Imperial estimated, subject to the assumption of an unlimited market at January 1, 1972, that a peak MER capacity of 95,000 BOPD could be achieved by 1975 and maintained for 2 years. This peak capacity would be attained by installing artificial lift and drilling 4 infill wells. Imperial did not believe water coning will be a problem in this pool because the high productivity area is remote from the oil-water interface.

The examiners believe that a reasonable estimate of the MER decline rate can be made for this pool by relating the remaining oil column to the cumulative production. The change in the parameters $\xi_{1.5}$ and ξ_2 with cumulative production are shown in Figure 9. If the MER capacity were restricted by coning considerations it might be expected to decline in proportion to the parameter ξ_2. Although the examiners agree with Imperial that the MER capacity will not be limited by coning, they are concerned that excessive production rates may lead to water fingering and premature water breakthrough. Thus, the examiners have indicated the MER capacity to decline in proportion to the parameter $\xi_{1.5}$. This decline rate corresponds to approximately 15 per cent per year. When the MER capacity is declined in this manner, an appropriate peak MER capacity is 90,000 BOPD. Figure 9 shows that the examiners' estimate of peak MER capacity is of the same general level suggested by K = 9,000 in the PRL formula at the corresponding cumulative production.

Judy Creek Beaverhill Lake B Pool

The Judy Creek Beaverhill Lake B Pool receives some natural water influx, but is generally very similar to the Judy Creek Beaverhill Lake A Pool. Imperial estimated that a peak MER capacity of 35,000 BOPD could be reached by 1975. The capacity would be attained by installing artificial lift and drilling 4 infill wells. It also estimated that the peak MER could be maintained for 2 years. Figure 10 shows this projection of MER performance.

The examiners' method of analysis for this pool, shown in Figure 10, is similar to that used for the Judy Creek Beaverhill Lake A Pool. The estimated decline in MER is approximately linear and corresponds to a decline rate of 14.9 per cent per year. The examiners' estimate a peak MER capacity of 30,000 BOPD having regard for the present worth aspects of installing enlarged facilities. They also estimate the decline in the MER will start after a cumulative production of some 57,000 MSTB. The examiners' estimate of peak MER capacity is similar to the rate from the PRL formula at the same cumulative production.

Meekwap D-2 A Pool

The Meekwap D-2 A Pool has limited production history and is still on primary depletion. Samedan estimated the developed wellhead capacity to be 15,000 BOPD. Until more data is available for this pool the examiners recommend using the PRL formula (K = 9,000) to estimate the MER. For the recognized reserve this calculation indicates a peak MER of 4,000 BOPD.

Simonette D-3 Pool

Oil production in the Simonette D-3 Pool is currently limited to 6,000 BOPD by the solution gas processing capacity of 18 MMCF/D. Shell estimated the peak MER capacity to be 12,300 BOPD based on the economics of enlarging the gas conservation facilities to 37 MMCF/D. Shell believed that the peak MER could be reached by mid 1973 and maintained until 1980 by drilling 3 infill wells. It estimated that the MER would decline at approximately 20 per cent per year thereafter. The relation of this MER forecast with respect to current recovery and the recognized reserve of 57,800 MSTB is shown in Figure 11.

The examiners are concerned with current water production and the effect that increased production rates could have on ultimate recovery. They agree with Shell that the peak MER will initially be limited by plant economic factors, but they also believe that water coning will limit the capacity in the latter stages of depletion. The examiners believe it reasonable to assume that the capacity of this pool will start to decline when the oil-water contact has advanced to the point where the parameter ξ_2 has been reduced to one-half its initial value. Following this point, which occurs at some 28,000 MSTB cumulative oil production, the decline rate is estimated at 13.6 per cent. The examiners' estimate of peak MER capacity is somewhat below that given by the PRL formula.

Swan Hills Beaverhill Lake A & B Pools

Home considered five different areas within the reef build-up of the Swan Hills Beaverhill Lake A & B Pools and prepared a schedule of estimated rates for the period 1972 to 1980. It estimated that about 20 wells would be drilled and placed on production in 1973. Home's schedule of rates is closely approximated by the MER forecast shown in Figure 12. The peak MER capacity of 140,000 BOPD occurs in 1974 with a decline rate of approximately 8 per cent per year thereafter. The examiners agree with Home's MER forecast. They also note that the peak MER capacity is near the rate suggested by the use of K = 7,000 in the PRL formula at the same cumulative production.

Swan Hills Beaverhill Lake C Pool

There are several waterflood schemes operating in the Swan Hills Beaverhill Lake C Pool. Shell estimated that the MER of these schemes with the existing wells would increase from the current 21,000 BOPD to 28,000 BOPD by 1974. It also estimated that by drilling 4 infill wells and 11 development wells the peak MER would be 32,000 BOPD, and that the MER would have a decline rate of 10 per cent per year. These MER forecasts are shown in Figure 13.

The current ratio of capable to operated wells is approximately 1.37. Thus, if it is assumed that the average productivity of the currently shut in wells is comparable to that of the producing wells, an MER of approximately 28,000 BOPD is indicated. The examiners believe that as more wells experience water breakthrough additional drilling may be required to meet a peak MER of 28,000 BOPD in 1974. The examiners estimate a decline rate of 7.3 per cent per year which is comparable to the estimated decline rates of similar Beaverhill Lake pools. The estimate of peak MER capacity of 28,000 BOPD at a cumulative production of 60,000 MSTB is some 9,000 BOPD less than that indicated by the PRL formula with K = 7,000.

Swan Hills South Beaverhill Lake A & B Pools

Figure 14 shows the MER forecasts for the Swan Hills South Beaverhill Lake A & B Pools. Amoco estimated that a peak MER of 120,000 BOPD could be achieved in 1974 by drilling 100 infill wells. Amoco's 1970 submission stated that the peak MER of 120,000 BOPD could be maintained for two years. Assuming this to still be the case, a decline rate of some 22.7 per cent per year would be indicated. The 121 wells presently connected to production facilites have a current capacity of 52,000 BOPD which is expected to increase to approximately 75,000 BOPD at peak MER conditions. The 100 infill wells would add approximately 45,000 BOPD to the pool productivity.

The examiners believe Amoco's peak MER capacity estimate of 120,000 BOPD to be optimistic in relation to other Beaverhill Lake pools. They question both the magnitude of the 100 well infill drilling program and the projected results it would achieve. The examiners recommend adopting a peak MER of 75,000 BOPD and they believe some infill drilling would be required to reach this capacity. The examiner's have used a decline rate of 9.6 per cent which is slightly higher than that recommended for the Swan Hills Beaverhill Lake A & B Pools.

Virginia Hills Beaverhill Lake Pool

Shell estimated that a peak MER of 50,000 BOPD could be reached by 1974. Shell also estimated that by drilling 9 infill wells in 1972 the peak MER could be increased to 60,000 BOPD. It said that if the pool was produced at capacity, the MER would decline to 12,000 BOPD by 1980. This would correspond to a constant percentage decline rate of 26.8 per cent per year.

Having regard for the peak MER indicated by the PRL formula and the similarity to other Beaverhill Lake Pools, the examiners estimate the peak MER capacity of the subject pool is about 40,000 BOPD. They believe the peak MER would start to decline almost as soon as it was achieved. Figure 15 shows the various MER capacity estimates and the decline rates which would result in recovery of the recognized reserve of 171 MMSTB. The examiners recommend that a peak MER capacity of 40,000 BOPD and a decline rate of 12 per cent per year be used to prepare the Board's forecast of growth and decline of the provincial MER.

RECOMMENDATIONS OF THE EXAMINERS

The examiners recommend that the reserve factors and the reserves listed in Table I and their interpretation of the peak MER's listed in Table III be adopted.

VIEWS OF THE BOARD

The Board agrees with the recommendation of the examiners.

DECISION

The Board has adopted the reserve factors and reserves listed in Table I and the examiners' estimates of the peak MER's listed in Table III. The reserves become effective May 1, 1972.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
April 14, 1972

TABLE I

RESERVE FACTORS - POOLS AT FEBRUARY 1972, RESERVES HEARING

POOL	AREA ACRES	PAY THICKNESS FEET	POROSITY FRACTION	WATER SATURATION FRACTION	OIL SHRINKAGE FACTOR FRACTION	INITIAL OIL IN PLACE MSTB	POOL RECOVERY PRIMARY FRACTION	POOL RECOVERY ENHANCED FRACTION	RECOVERABLE OIL PRIMARY MSTB	RECOVERABLE OIL ENHANCED MSTB	RECOVERABLE OIL TOTAL MSTB
RUNDLE											
SUNDRE RUNDLE A (INCREMENT)	360	19.4	.051	.22	.73	1,580	.15		237		237
NISKU D-2											
MEEKWAP D-2A	4,680	28.9	.085	.15	.74	56,000	.30		16,800		16,800
STURGEON LAKE SOUTH D-2A	900	21.1	.073	.24	.68	5,560	.30		1,670		1,670
WEST DRUMHELLER D-2A	4,200	45.2	.05	.20	.74	43,600	.63		27,500		27,500
LEDUC D-3											
FENN-BIG VALLEY D-3A	850	14.1	.05	.20	.82	3,100	.70		2,170		2,170
INNISFAIL D-3	7,530	77.0	.06	.13	.53	124,000	.60		74,400		74,400
NEVIS D-3E	84	150.0	.12	.17	.82	8,000	.50		4,000		4,000
REDWATER D-3	37,500	103.0	.065	.25	.89	1,300,000	.62		806,000		806,000
ST. ALBERT BIG LAKE D-3A	249	142.0	.11	.06	.82	23,300	.62		14,400		14,400
STETTLER D-3B	279	18.6	.065	.15	.83	1,850	.60		1,110		1,110
STETTLER SOUTH D-3	420	12.9	.084	.12	.80	2,480	.55		1,360		1,360
STURGEON LAKE SOUTH D-3	17,200	81.4	.047	.14	.65	285,000	.55		157,000		157,000
BEAVERHILL LAKE											
CARSON CREEK NORTH BEAVERHILL LAKE A	9,270	30.2	.083	.13	.55	86,300	.15	.30	12,900	25,900	38,800
CARSON CREEK NORTH BEAVERHILL LAKE B	15,000	51.3	.089	.21	.61	256,000	.16	.31	41,000	79,400	120,000
KEG RIVER											
RAINBOW KEG RIVER II											
PRIMARY AREA	31	145.2	.11	.10	.78	2,700	.50		1,350		1,350
WATERFLOOD AREA	46	387.8	.11	.10	.78	22,300	.50	.03	11,200	1,780	12,900
RAINBOW KEG RIVER JJ	211	255.1	.052	.18	.73	13,000	.43	.08	5,590	1,040	6,630

TABLE II

COMPARISON OF OIL IN PLACE AND RECOVERABLE RESERVES

(Thousand of Stock Tank Barrels)

Pool	Previous		Operator		Examiners	
	N	U	N	U	N	U
Sundre Rundle A (Increment)	-	-	2185	545	1580	237
Meekwap D-2 A	71100	21300	66876	19500	56000	16800
Sturgeon Lake South D-2 A	6000	900	5180	2140	5560	1670
West Drumheller D-2 A	41300	26000	51048	32160	43600	27500
Fenn Big-Valley D-3 A	3390	2000	3358	2552	3100	2170
Innisfail D-3	124000	74400	124900	87400	124000	74400
Nevis D-3 E	16500	7430	9501	4991	8000	4000
Redwater D-3	1300000	780000	1277000	848000	1300000	806000
St. Albert Big-Lake D-3 A	23300	14000	23500	16300	23300	14400
Stettler D-3 B	1830	915	1913	1186	1850	1110
Stetter South D-3	2000	900	2557	1534	2480	1360
Sturgeon Lake South D-3	265000	146000	287500	158125	285000	157000
Carson Creek North Beaverhill Lake A	72500	33000	82089	36940	86300	38800
Carson Creek North Beaverhill Lake B	235000	111000	266677	125338	256000	120000
Rainbow Keg River II	28000	14700	27574	18381	25000	14300
Rainbow Keg River JJ	17000	7500	19591	12591	13000	6630

TABLE III

COMPARISON OF PEAK MER CAPACITY

(Stock Tank Barrels Per Day)

Pool	Previous	Operator	Board
Bellshill Lake Blairmore	10,000	8,600	8,000
Clive D-2 A	7,000	5,000	5,000
Clive D-3 A	15,500	10,500	10,000
Gilby Jurassic B	2,700	4,000	4,000
Golden Spike D-3 A	70,000	80,000	70,000
Harmattan Elkton Rundle C	14,500	12,000	8,000
Judy Creek Beaverhill Lake A	75,000	95,000	90,000
Judy Creek Beaverhill Lake B	30,000	35,000	30,000
Meekwap D-2 A	-	-	4,000
Simonette D-3	21,600	12,300	12,000
Swan Hills Beaverhill Lake A&B	196,000	140,000	140,000
Swan Hills Beaverhill Lake C	28,100	32,000	28,000
Swan Hills South Beaverhill Lake A & B	120,000	120,000	75,000
Virginia Hills Beaverhill Lake	80,000	60,000	40,000

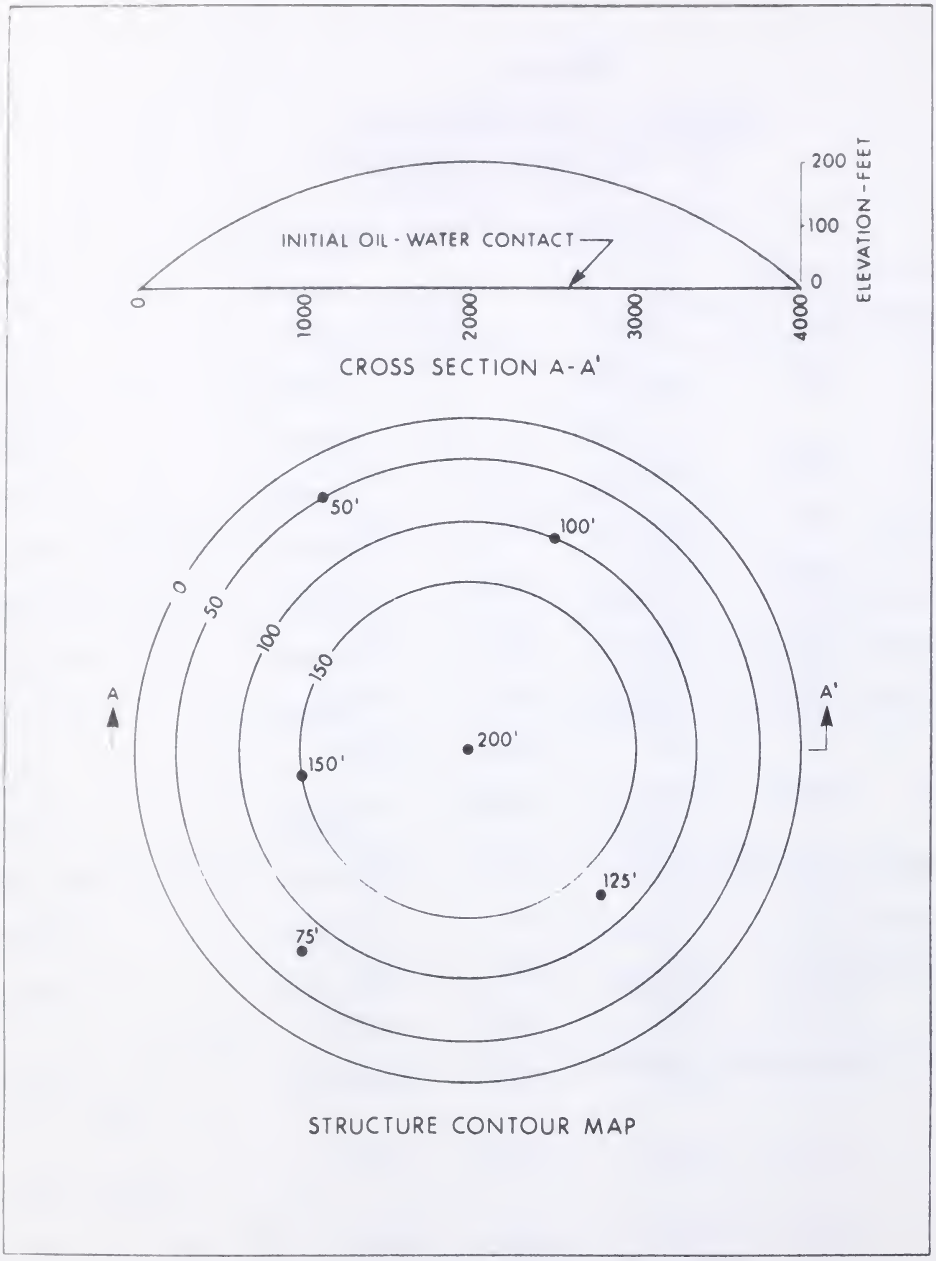

FIGURE 1 - HYPOTHETICAL RESERVOIR CONFIGURATION

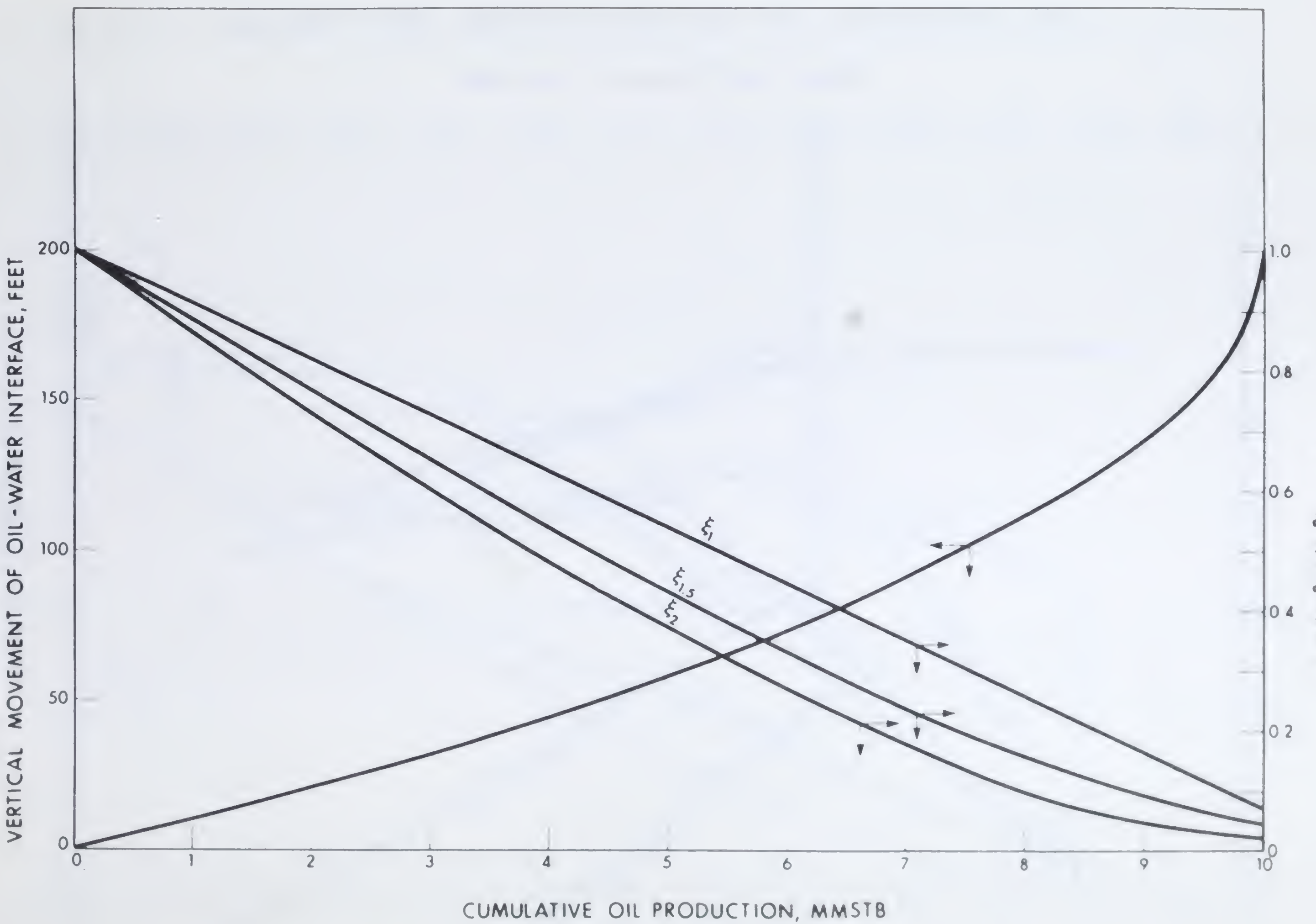

FIGURE 2 - SOME CHARACTERISTICS OF THE HYPOTHETICAL RESERVOIR$_1$

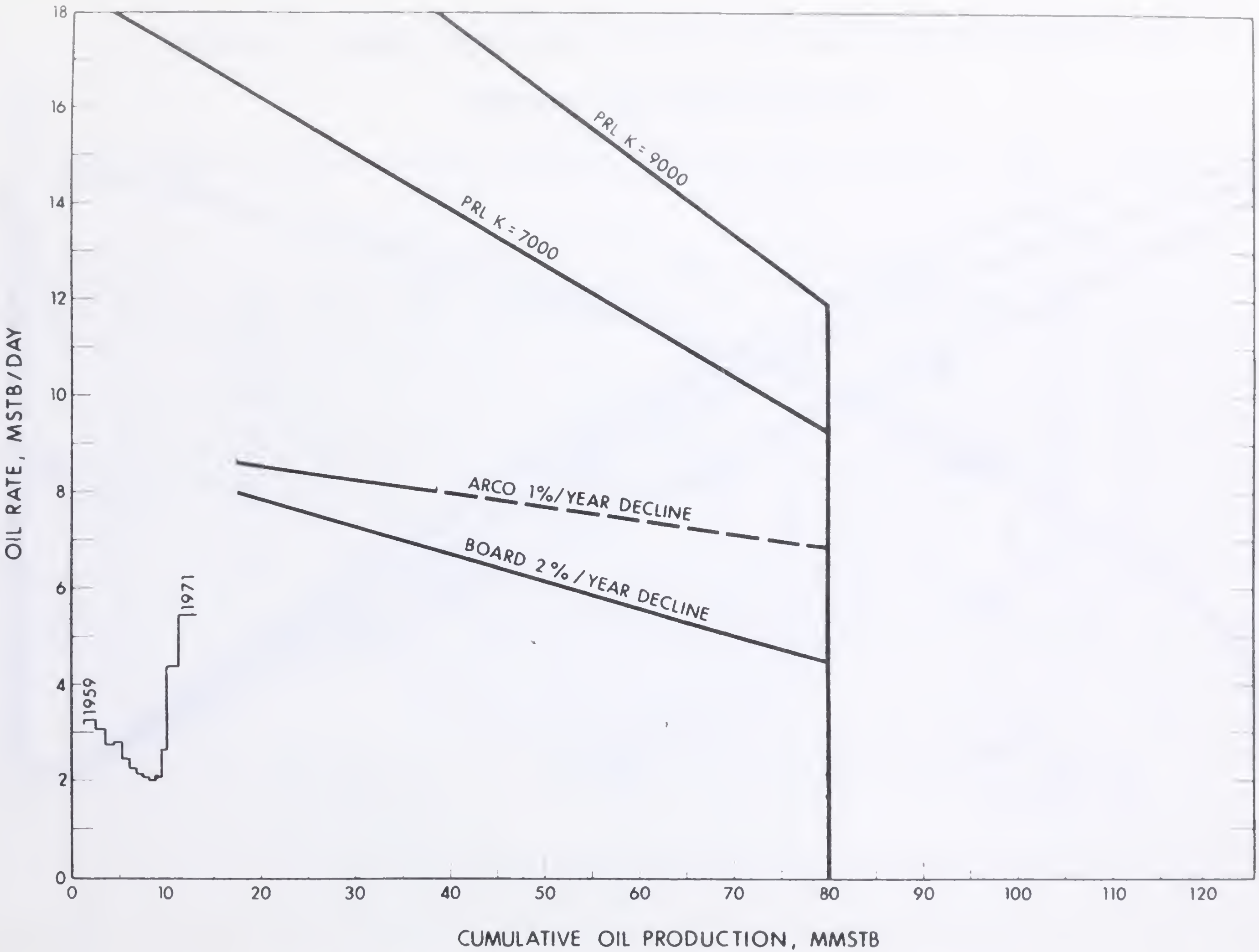

FIGURE 3 - MER FORECAST - BELLSHILL LAKE - BLAIRMORE POOL

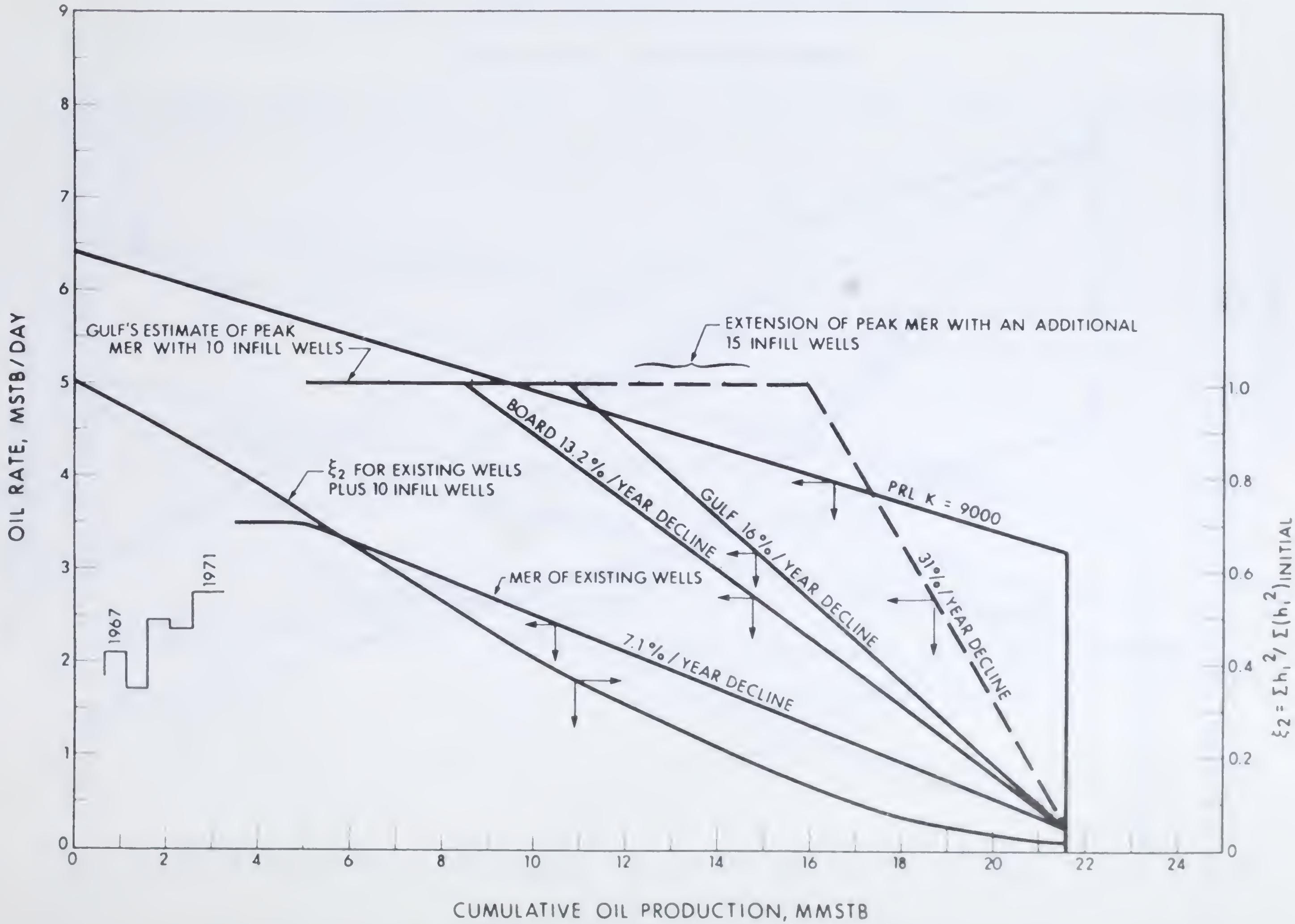

FIGURE 4 - MER FORECAST - CLIVE D-2A POOL

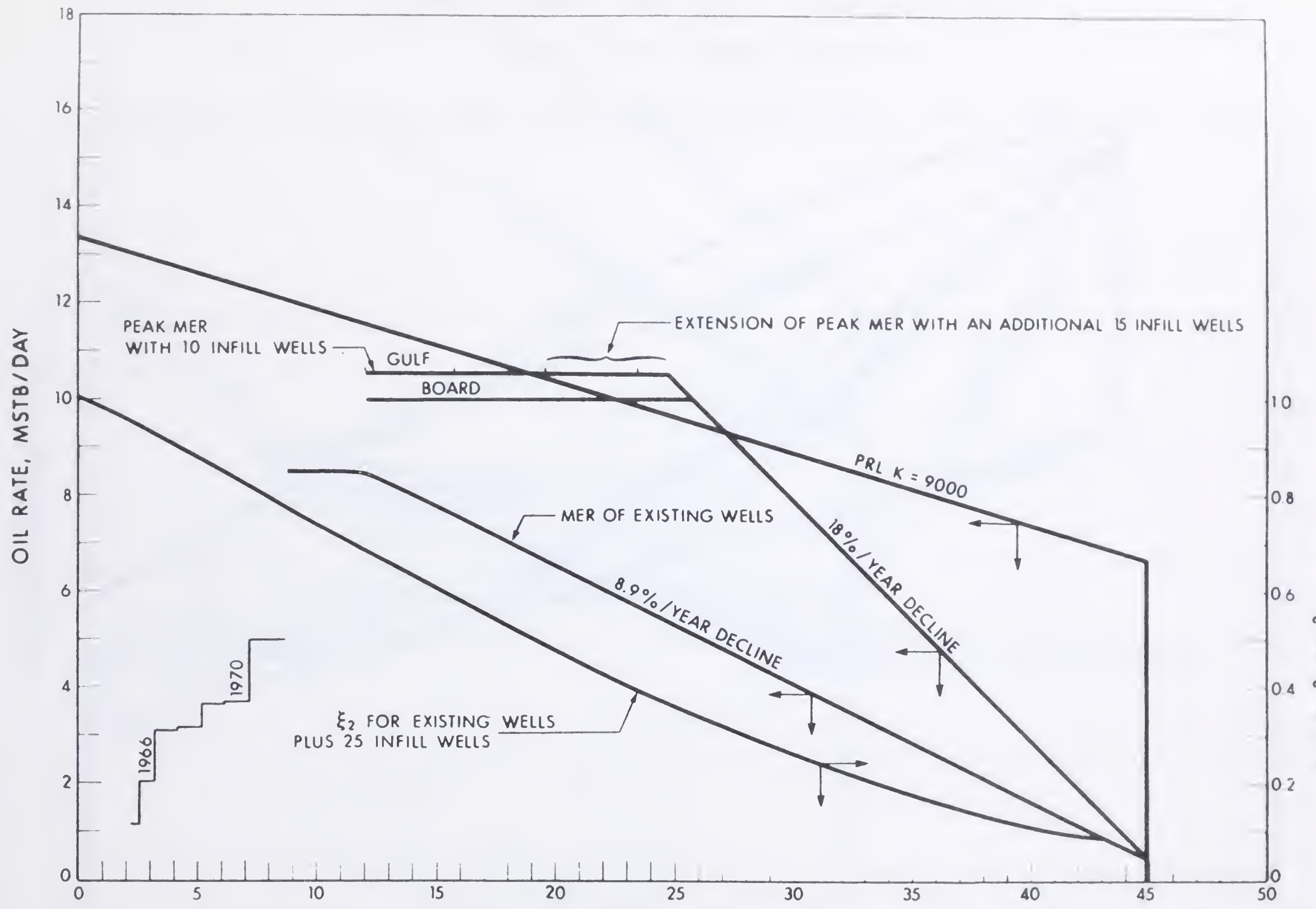

FIGURE 5 - MER FORECAST - CLIVE D-3A POOL

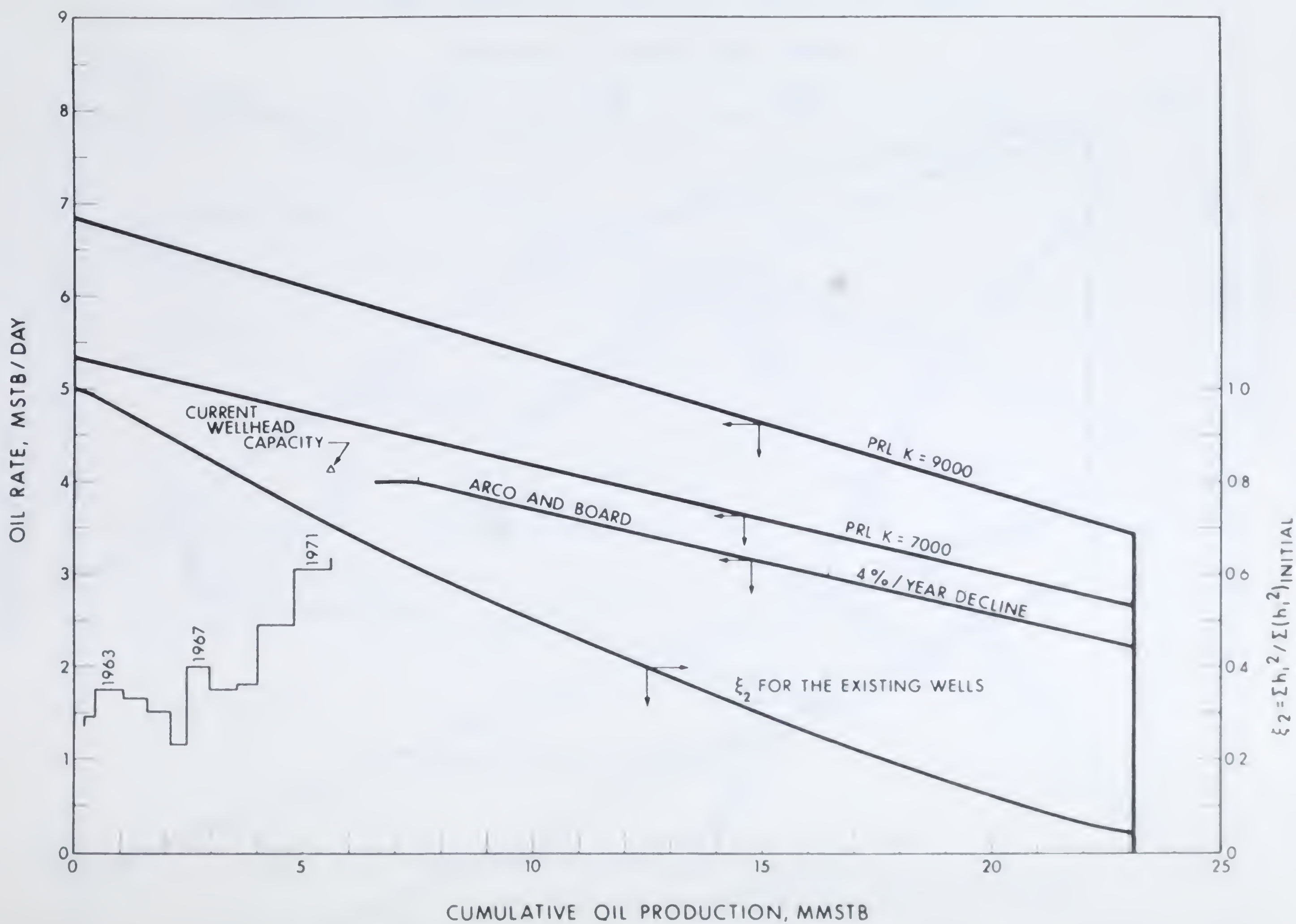

FIGURE 6 - MER FORECAST - GILBY - JURASSIC B POOL

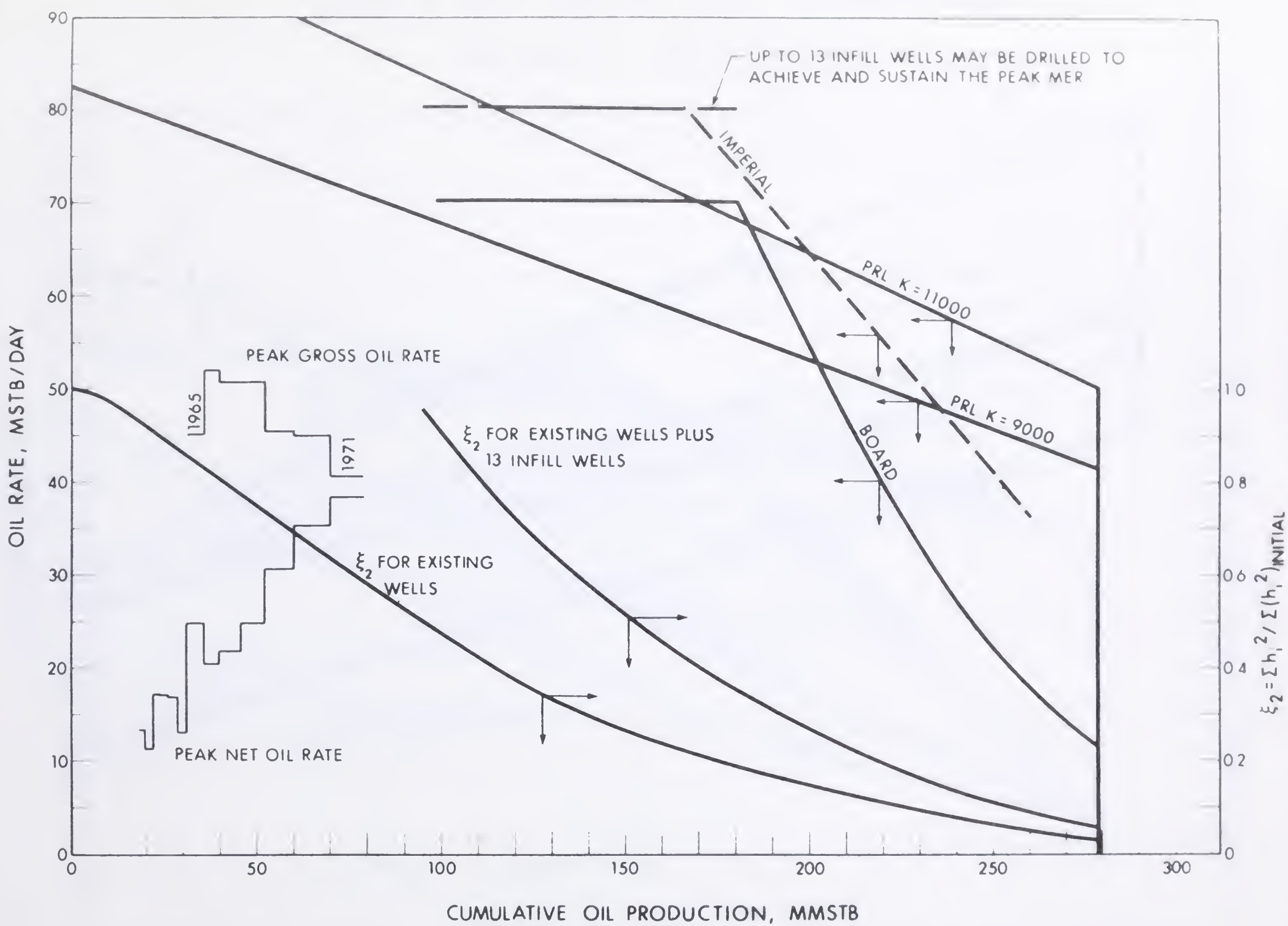

FIGURE 7 - MER FORECAST - GOLDEN SPIKE D-3A POOL

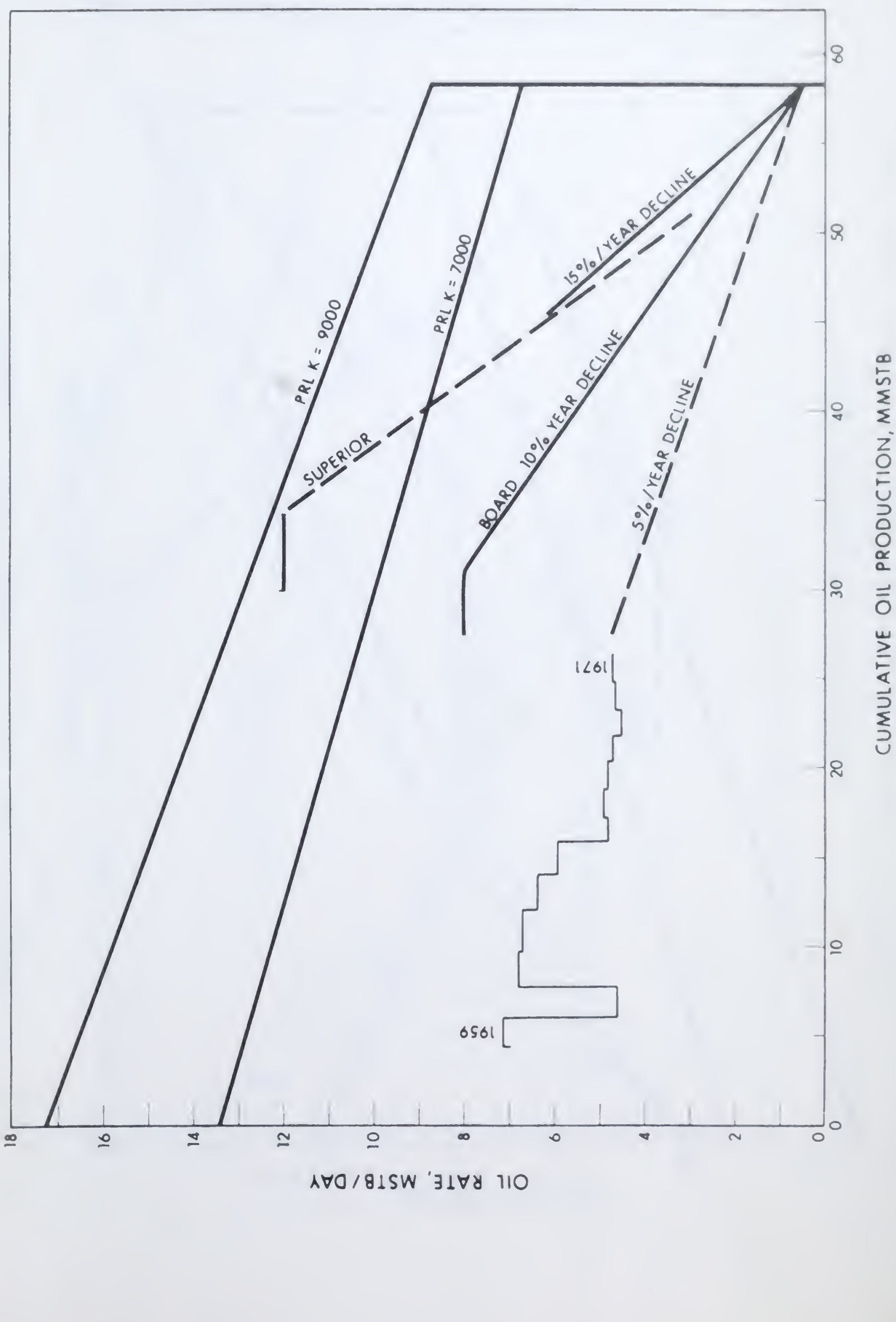

FIGURE 8 - MER FORECAST - HARMATTAN ELKTON RUNDLE C POOL

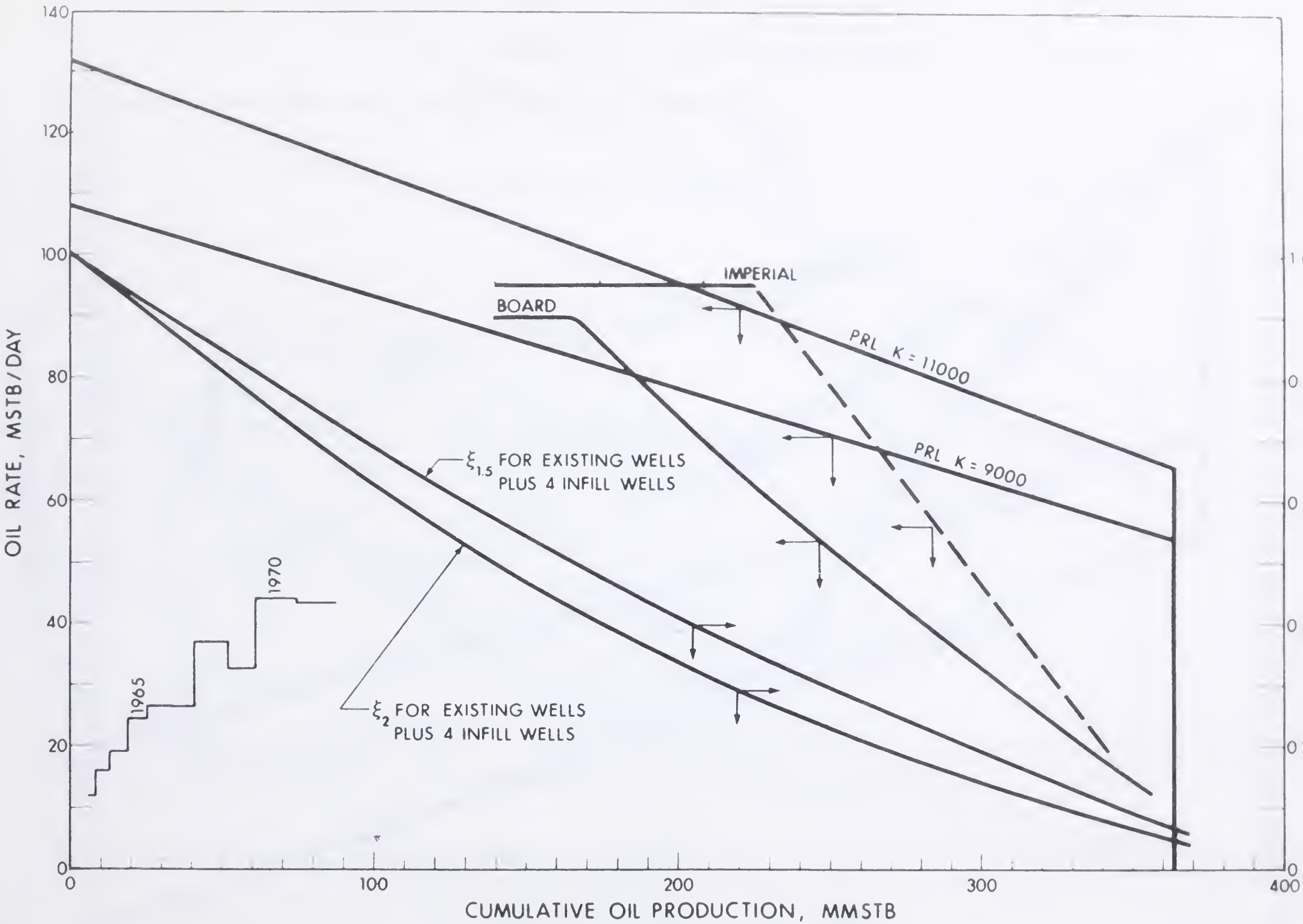

FIGURE 9 - MER FORECAST - JUDY CREEK BEAVERHILL LAKE A POOL

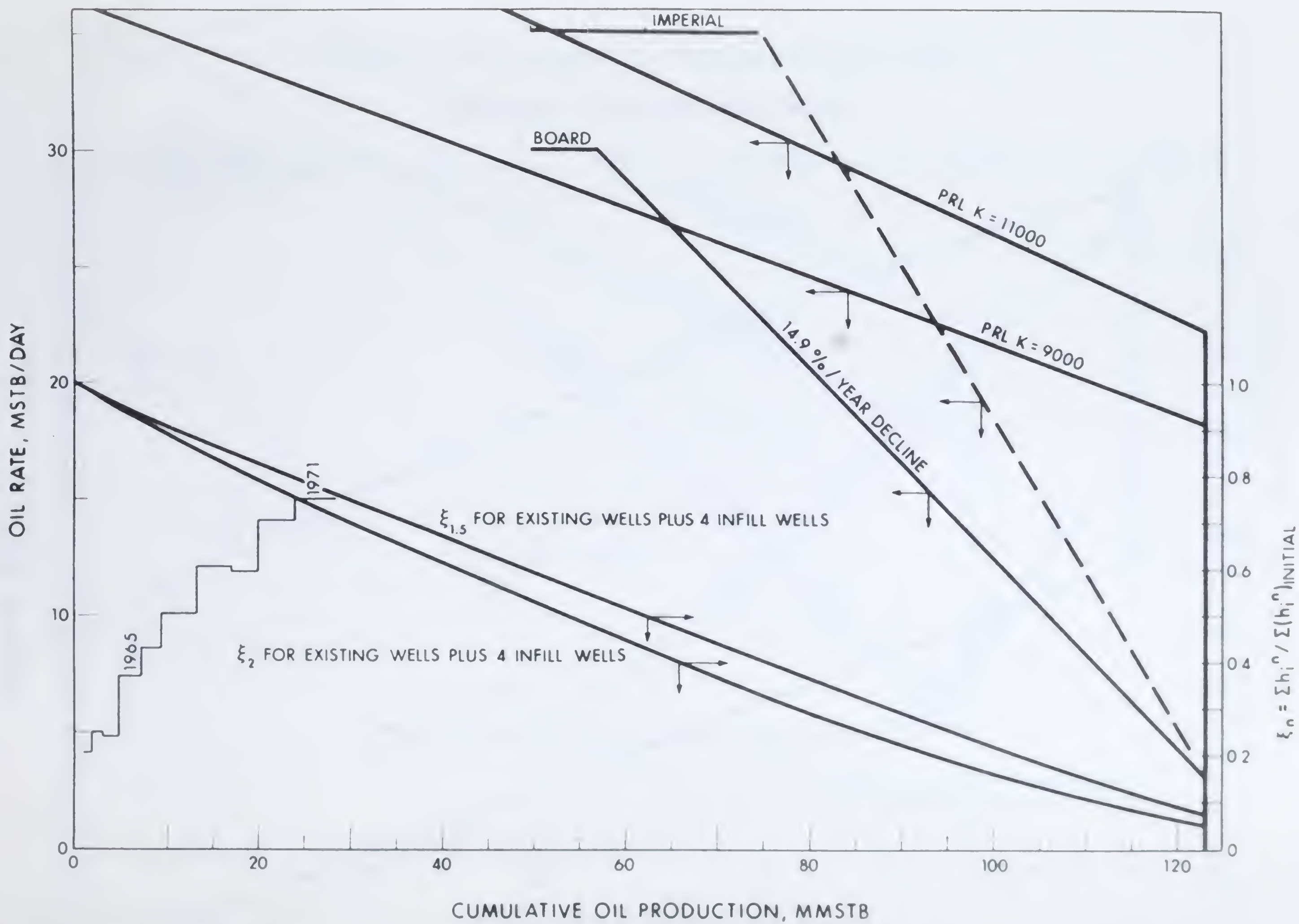

FIGURE 10 - MER FORECAST - JUDY CREEK BEAVERHILL LAKE B POOL

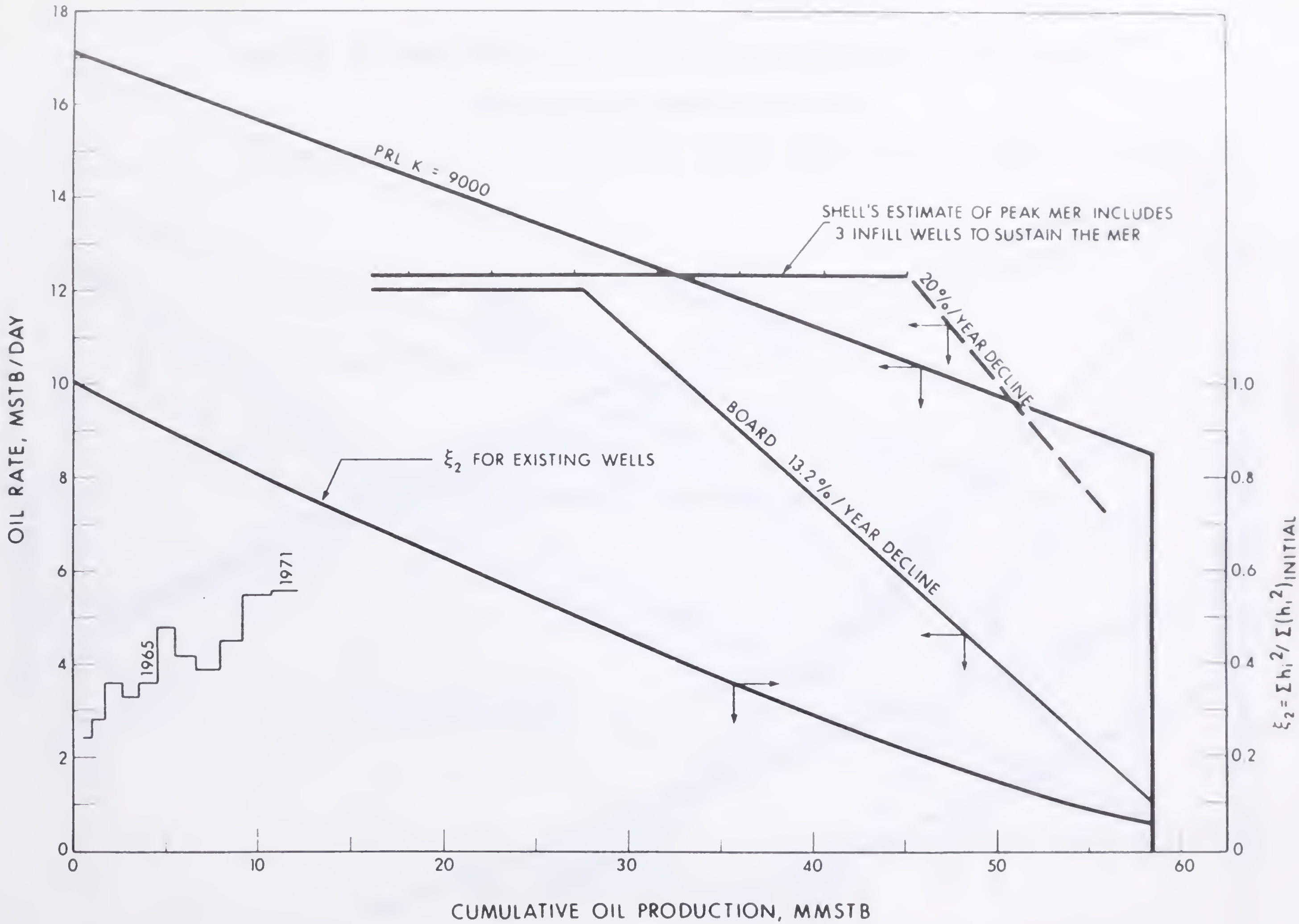

FIGURE 11- MER FORECAST - SIMONETTE D-3 POOL

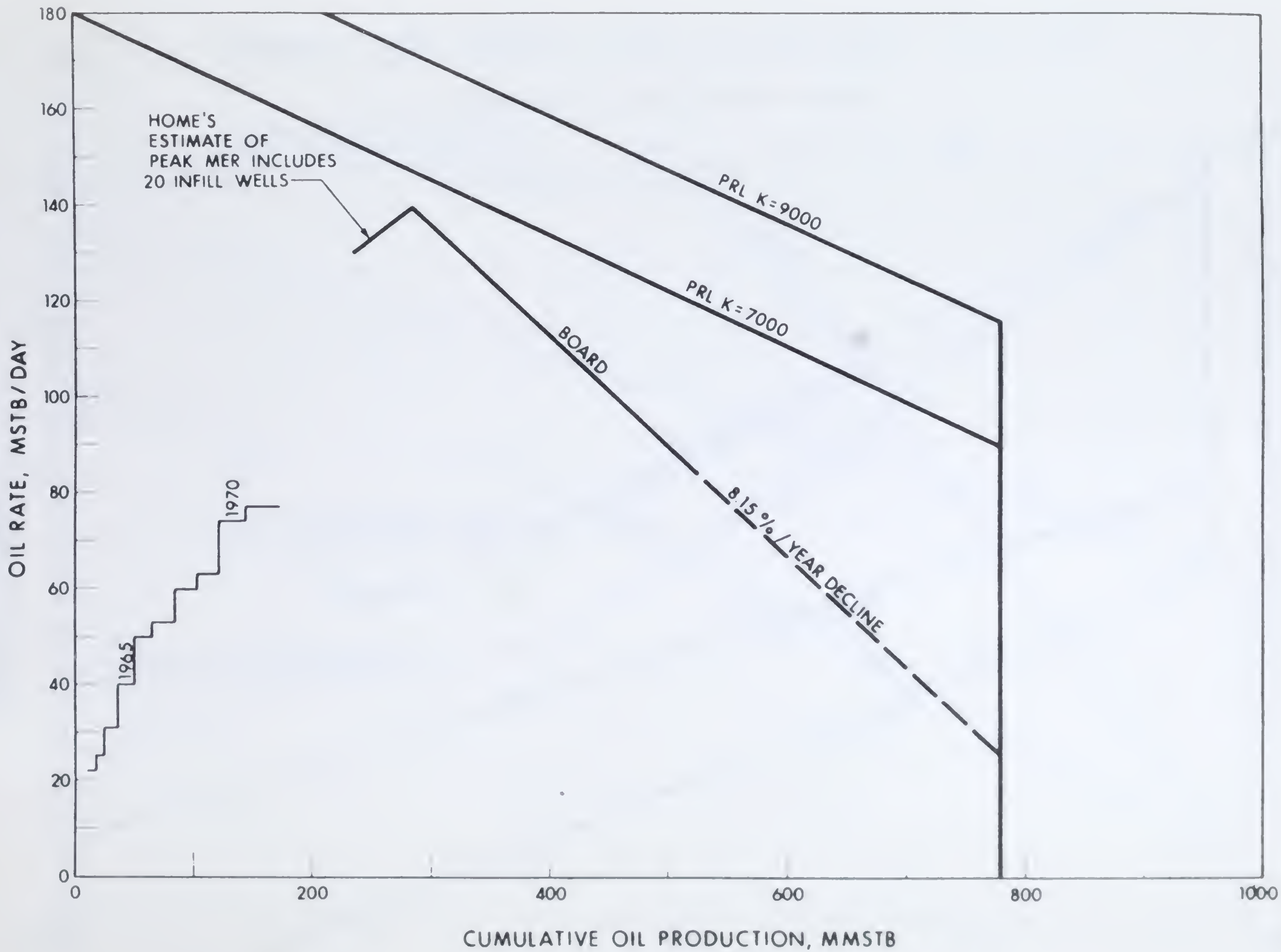

FIGURE 12 - MER FORECAST - SWAN HILLS BEAVERHILL LAKE A & B POOLS

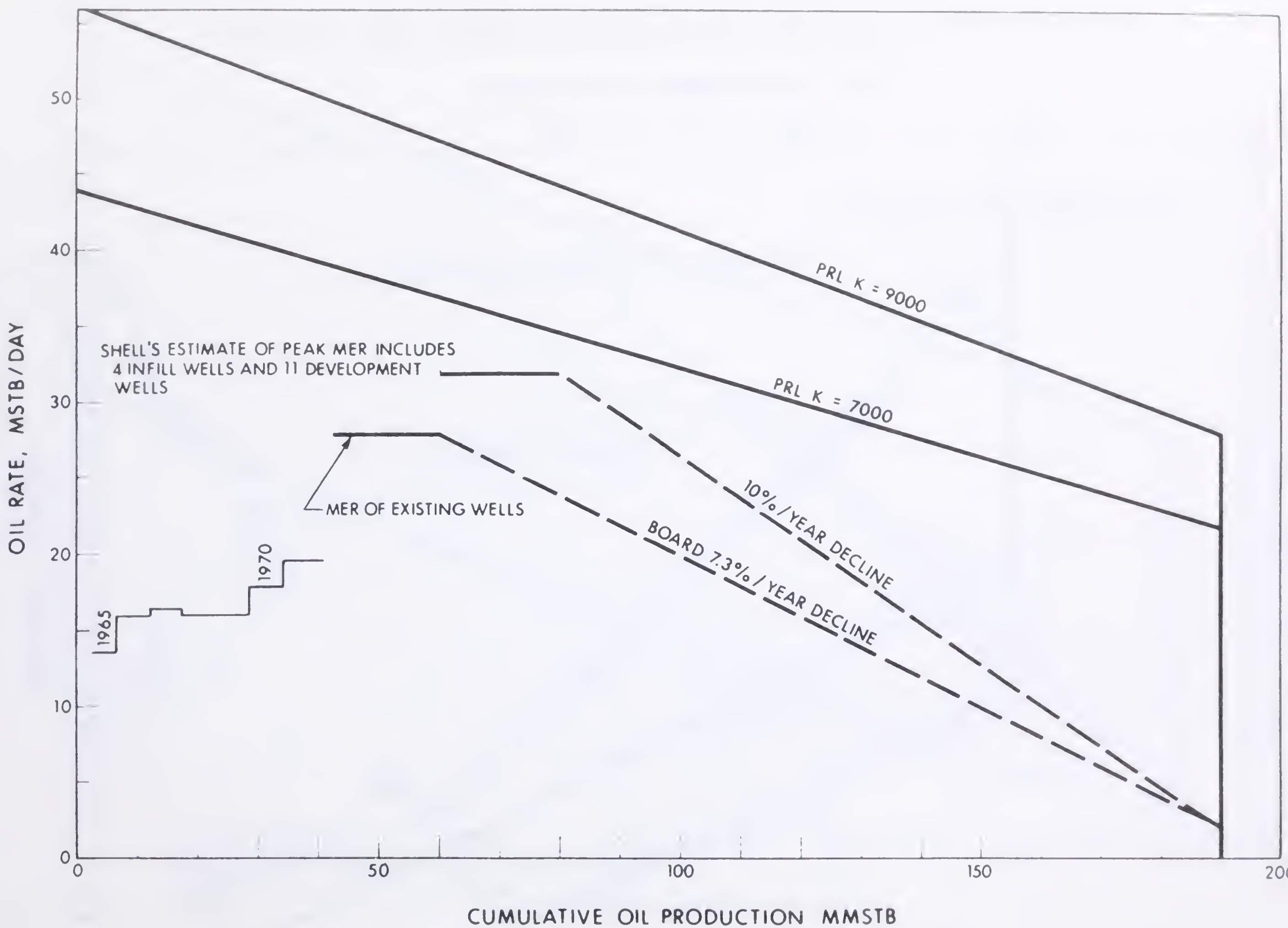

FIGURE 13 - MER FORECAST - SWAN HILLS BEAVERHILL LAKE C POOL

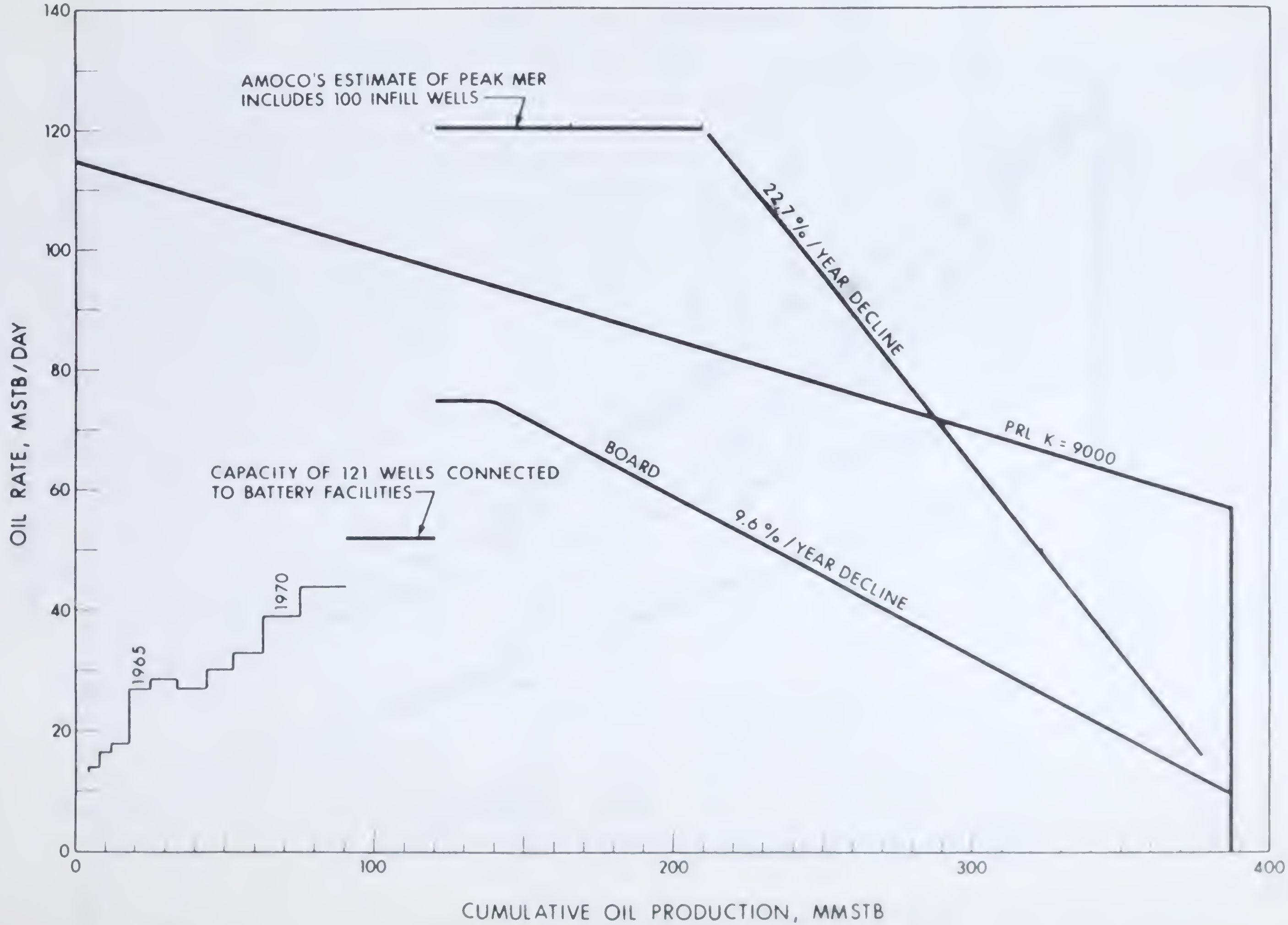

FIGURE 14 - MER FORECAST - SWAN HILLS SOUTH BEAVERHILL LAKE A&B POOLS

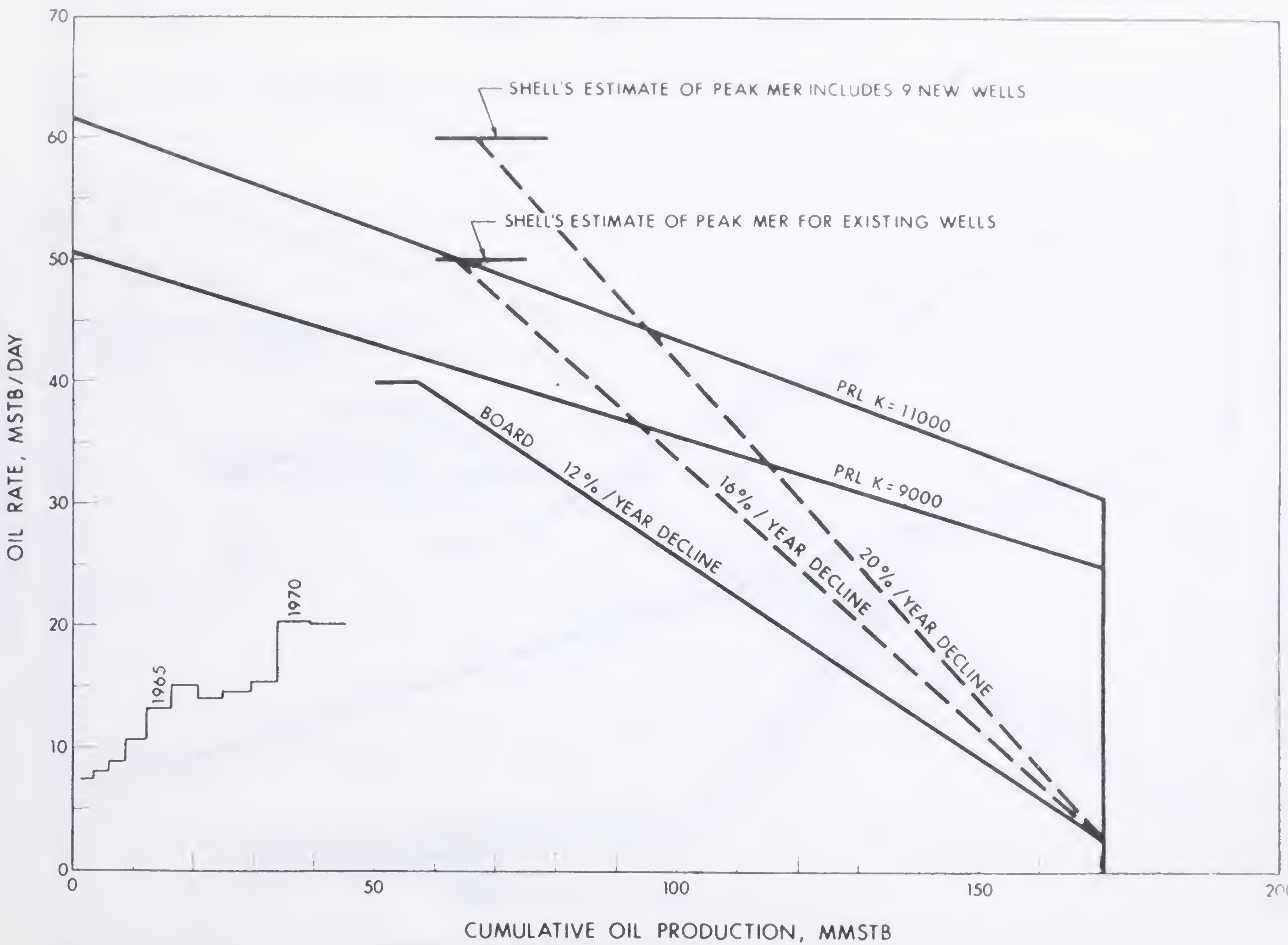

FIGURE 15 - MER FORECAST - VIRGINIA HILLS BEAVERHILL LAKE POOL

ENERGY RESOURCES CONSERVATION BOARD

Decision No. 72-[illegible]
Proceeding No. 5124
Application No. 6078

OLDS WABAMUN A POOL
ENHANCED CRUDE OIL RECOVERY CONCURRENT PRODUCTION
PROVISIONS AND CRUDE OIL PRODUCTION (GPP) LIMITATIONS

INTRODUCTION

In its decision issued March 25, 1971, on Proceeding No. 5124 with amendments to deadline dates contained in the Board's letter dated August 13, 1971, the Board set out the following:

"On the basis of all the information made available in connection with Proceeding No. 5124 and subsequent to it, the Board is satisfied that overall hydrocarbon recovery from the Olds Wabamun A Pool can be significantly improved by appropriate enhanced recovery operations.

Accordingly, in order to prevent waste, unless the Board

(a) decides after the filing of the detailed study by November 1, 1971, that enhanced recovery operations are not feasible, or

(b) receives a suitable application by November 1, 1971, to implement an enhanced recovery scheme in the Olds Wabamun A Pool by April 1, 1972,

it will seek the approval of the Lieutenant Governor in Council to require enhanced recovery operations in the Olds Wabamun A Pool on or before April 1, 1972."

The Board received a detailed study from Shell Canada Limited on November 29, 1971, focused primarily on the feasibility of enhanced recovery, but containing also revised predictions for primary prorated and primary GPP conditions. The Board considered Shell's detailed enhanced recovery studies along with similar studies previously provided by the Board staff in regard to the requiring of enhanced recovery.

Respecting production rates from the north-east gas cap, in a letter dated November 24, 1971, (registered as Application No. 6078) BP Oil and Gas Ltd. made application under section 38, clause (e) of The Oil and Gas Conservation Act for an order allowing the production of gas from the well, Triad Olds A10-34-32-2, concurrently with oil from the Olds Wabamun A Pool. This evidence in addition to the new information provided by Shell for primary prorated and primary GPP cases, was considered by the Board in deciding on limits to oil and gas production rates.

Enhanced Recovery of Crude Oil

Shell submitted on October 29, 1971, a fully revised interpretation of the primary depletion and water flood performance of the Olds Wabamun A Pool using a 2-D simulation approach similar to that previously employed by the Board staff. The results obtained for a full scale water flood are very similar to those previously submitted by the Board staff for a full scale water flood where neither Shell nor the Board staff make allowance for the effects of stratification and certain risks. Shell developed a number of water flood predictions using decreasing numbers of injection wells and water injection rates with the objective of establishing an optimum water flood scheme. Shell submitted the conclusion that there would be a net loss in overall recovered hydrocarbon energy comparing any water flood scheme with either primary prorated or primary GPP operation. It therefore concluded that water flooding was not only uneconomic but was undesirable from a net energy recovery viewpoint.

The Board has updated its views having regard for the previous study of the Board staff and the current submission by Shell. The Board believes that the appropriate water flood GPP case to evaluate is Shell's Case 3 adjusted to account for stratification and risk effects. The overall summation of Board staff, Shell and Board adopted values for primary prorated, primary GPP and water flood GPP are contained in the attached table.

The Board believes it appropriate to adopt Shell's updated prediction for primary prorated in that the prediction reflects substantially increased rates of production now anticipated relative to that assumed by the Board staff. Remaining recoveries and profits after January 1, 1972, adopted by the Board are 3.2 MMSTB, 45 Bcf, 59 trillion Btu heating value, nil additional capital invested and present worth before tax (PWBT) profit of $5 million. Comparable values for primary GPP are 3.4 MMSTB, 50 Bcf, 64 trillion Btu's, nil capital invested and PWBT profit of $7 million. In accordance with note (1) on the table, the Board believes that the remaining crude oil reserves may be as much as 0.5 MMSTB less if substantial quantities of gas are withdrawn from the north-east gas cap in the immediate future. As will be noted subsequently in this decision, the Board has taken steps to permit gas cap production from the north-east gas cap but with provision for restricted rates. On this basis, the Board believes that the estimated remaining reserves under primary prorated and primary GPP do not have to be reviewed.

The comparable water flood GPP cases developed by the Board staff and by Shell (Case 3 Modified) show fairly similar results for ultimate

crude oil recovery. On the evidence presented, the Board believes it appropriate to assign a remaining crude oil reserve of some 8 MMSTB for a full scale water flood. In this respect the Board's previously expressed views remain substantially unchanged; that is, water flood will yield incremental oil recovery of some 4 to 5 million barrels over either primary GPP or primary prorated. Concerning the casing head gas recovery, the Board believes the new evidence provided by Shell confirms that there will be a substantial reduction in casing head gas production if a full scale water flood is implemented. The comparable values provided by the Board staff and Shell are 30 Bcf and 22 Bcf respectively and the Board believes that a value of 25 Bcf is reasonable. The Board notes that this is a significant downward reduction from the 40 Bcf it had previously adopted on the basis of the evidence then available. Net heating value provided under this scheme of operation is estimated by the Board to be some 72 trillion Btu. Concerning capital invested, the Board largely accepts detailed evidence provided by Shell but believes that some costs are on the high side and on this basis would attribute a capital investment of $3 million for a full scale water flood. The Board notes that the Board staff did not make provision for increases in product prices in its evaluation in the fall of 1970. The Board believes that allowance for oil and condensate price changes should have been made and that risk factors may not be as heavily weighted to the negative as Shell has assumed. On this basis, the Board estimates PWBT profit to be in the neighborhood of $4.8 to $5.2 million after allowing for stratification and risk effects and incorporating increases in oil, condensate and gas prices.

The Board concludes, as is indicated in the table, that water flooding could yield a net heating value gain of perhaps 8 trillion Btu over that obtainable under primary GPP. This is equivalent to approximately 1.5 MMSTB equivalent crude oil. However, the present value profit or loss position would be scarcely break even compared to primary GPP. Moreover, a substantial capital investment would be required relative to the amount of net heating value gained. (The Board notes but does not accept Shell's interpretation that there would be a net reduction in heating value under water flooding). The Board adopts the current interpretation as fully supplanting that contained in Table No. 1 to its Decision 71-4 issued on March 25, 1971, in which the PWBT value was estimated at some $7 million under water flood compared to some $3 million under primary prorated. The updated PWBT profit for primary prorated is higher than previously estimated because market demand for crude oil is now expected to be higher than before and PWBT profit for water flood has been reduced on the basis of much more detailed studies of capital requirements, costs, prices and probable risk.

The Board has therefore decided that it would be inappropriate to require enhanced recovery operations in the Olds Wabamun A Pool oil accumulation and withdraws its stipulations to that effect set out in Decision 71-4.

Oil and Gas Production Rates

Using the same 2-D model as that employed by Shell, BP Oil and Gas made predictions of ultimate recovery assuming the A10-34 well was produced at an average contract rate of 1.322 MMCF per day of raw gas. Based on its predictions it submitted the conclusion that, over the life of the oil column, an additional 108 MSTB of oil and condensate and 4.9 BSCF of raw gas would be recovered if the A10-34 well were continuously produced compared to the case where the well would remain shut-in.

The Board has reviewed the new evidence and other information provided by the Board staff and concludes that some reductions in crude oil recovery will result if the north-east gas cap is rapidly depleted. It cannot agree with BP Oil and Gas that a net gain in oil and condensate and gas cap recovery would result from production from the A10-34 well commencing at this time. On the other hand, the Board recognizes that undue economic hardship may be borne by BP Oil and Gas if the Board required an extended shut-in of the A10-34 well. The Board concludes that it would be appropriate to grant limited production from wells in close proximity to the oil accumulation completed in the north-east gas cap. Such operation should not significantly reduce oil recovery and would permit reasonable production income to gas wells.

The Board has estimated that the contract production rate of 1.322 MMSCF per day indicated by BP Oil and Gas would provide a reasonable economic return without incurring abnormal reservoir withdrawals from that region of the pool. At current reservoir conditions, withdrawals of 1.322 MMSCF per day would be equivalent to approximately 1000 reservoir barrels per day, and the Board will assign this limit to each of the four sections in the north-east gas cap in the vicinity of the oil accumulation.

The Board believes it desirable to continue the provisions previously set out in the concurrent production Approval No. 1062 issued to Amerada, which prohibits production from a nine-section area and limits total gas production from the Pool to 41 MMcfd determined on an annual basis.

The Board has also decided to continue to grant good production practice to the oil accumulation with a crude oil production limit of 43,500 barrels per month. The Board reasons that such operation will offer at least modest improvement in oil recovery over that obtainable under proration restrictions.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
April 18, 1972

Decision 72-4

OLDS WABAMUN A POOL JAN./72

REMAINING RECOVERIES AND PROFITS FROM 1/1/72

	Primary Prorated			Primary GPP			Waterflood GPP		
	BOARD STAFF	SHELL (CASE 1)	RECOMM-ENDED BOARD	BOARD STAFF	SHELL (CASE 2)	RECOMM-ENDED BOARD	BOARD STAFF	SHELL (CASE 3) Modified	RECOMM-ENDED BOARD
CRUDE OIL (MMSTB)	2.4	3.2	3.2 (1)	3.8	3.4	3.4 (1)	8.5	7.7	8
CASING HEAD GAS (BCF)	49(39)	55.7	45	56(42)	60.7	50	38(30)	22	35
HEATING VALUE (TRILLIONS OF BTUs)	58(49)	68.5	59	72(61)	74.1	64	86(79)	67	72
CAPITAL INVESTED	-	-	-	-	-	-	2.3	3.3	3
PW PROFIT ($ MILLIONS)	3.1	5.4	5	4.5	7.7	7	7.3	4.9 2.9 (2)	5.8 4.2 (3) 4.8-5.2 (4)

( ) Amount of casing head gas used in Board staff economic evaluation

(1) This value may be about 0.5 MMSTB less if large quantities of gas produced from North-west gas cap (ie. production from A10-34, 10-27 and 10-33 permitted).

(2) Shell's Case 3 adjusted to account for stratification (1.1 MM) and risk ($0.9 MM) effects.

(3) Board value adjusted to account for stratification ($1.1 MM) and risk (0.5 MM) effects.

(4) Possible Board values after including increases in product prices (oil, condensate & gas).

ENERGY RESOURCES CONSERVATION BOARD

Decision 72-5
Application No. 6116

CONCURRENT PRODUCTION OF OIL ZONE AND GAS CAP WITH GAS CAP CYCLING AND WATER FLOODING OF OIL ZONE HARMATTAN EAST RUNDLE POOL

THE APPLICATION AND HEARING

Shell Canada Limited, on behalf of itself and the working interest owners of the Harmattan East Unit No. 1, applied, pursuant to section 38 of The Oil and Gas Conservation Act, for approval of a scheme within the Harmattan East Unit No. 1 in the Harmattan East Rundle Pool for

(a) concurrent production of the oil accumulation and its associated gas cap, with commencement of gas sales at an annual average rate of 120 million cubic feet per day and a daily maximum rate of 150 million cubic feet per day,

(b) enhanced recovery by water flooding the oil zone, and

(c) continuation of cycling in the gas cap adjacent to the oil zone at an annual average rate of 30 million cubic feet per day until approximately the end of 1978 with supplemental injection of from 15 to 20 million cubic feet per day of gas produced from the oil zone wells into the cycling injection wells.

The application was heard on March 14, 1972, by the Energy Resources Conservation Board with G. W. Govier, P. Eng., D. R. Craig, P. Eng. and Vernon Millard sitting.

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Shell Canada Limited	A. P. G. Walker J. E. Klinck H. J. Lyon G. G. Hoover, P. Eng. W. H. Mensch (of D. R. McCord and Associates)	Shell

	Represented by	Abbreviation Used in Report
Board Staff	P. M. Stanton, P. Eng. J. A. Bray, P. Eng. N. G. Berndtsson, P. Eng.	

BACKGROUND

The Harmattan East Rundle Pool is subject to two unit operating agreements. The northern part of the pool, which has no downdip oil zone directly associated with it, is operated by the Garrington Elkton Gas Unit No. 1. The southern part of the pool is subject to the Harmattan East Unit No. 1 which is operated by the applicant. The unit agreement for the latter provides for different participation for the oil zone and the gas cap owners. The reservoir communication between the two unitized areas is minimal because of poorly developed porosity and permeability.

The Garrington Elkton Gas Unit No. 1 currently produces gas for sale at a minimum contract rate of 13 million cubic feet per day. The Harmattan East Unit No. 1 cycles the gas cap at a rate of approximately 105 million cubic feet per day to recover natural gas liquids. Board Approval No. 597 authorizes the cycling scheme. To date, the cumulative average recovery of natural gas liquids is approximately 49 barrels per million cubic feet of gas cycled. Replacement of reservoir voidage created by the cycling scheme is not required. The solution gas from the oil production is conserved and injected to the gas cap. Oil production is subject to proration.

As of December 31, 1971, 26.1 million stock tank barrels of crude oil and 15.4 million barrels of natural gas liquids had been produced from the pool. Twenty-nine billion cubic feet of residue gas had been produced and sold from the Garrington Elkton Gas Unit No. 1 as of the same date.

The Harmattan East Rundle Pool is a monoclinal stratigraphic trap dipping gently westward at less than one degree. The reservoir, in the Turner Valley Formation, consists of fine grained dolomite locally interbedded with dense argillaceous limestone. The limits of the reservoir are determined by permeability barriers and entrenched erosional channels. The average original gas-oil contact of the main oil zone and of the south salient was 4970 feet subsea and 4920 feet subsea respectively. No known aquifer is associated with the pool. By May, 1971 the average reservoir pressure in the Harmattan East Unit No. 1 had declined to 3190 pounds per square inch gauge (psig) at 4970 feet subsea from an initial reservoir pressure of 3422 psig.

The Board does not consider oil and gas in place to be an issue in this application. From its model studies, Shell adopted the history matched oil in place and gas cap gas in place of 206 million stock tank barrels and 900 billion cubic feet respectively for the Harmattan East Unit No. 1 area. The gas in place was little different than Shell's volumetric determination while the 206 million barrels of oil in place was 3.7 per cent lower than Shell's volumetric determination. Shell's reservoir parameters are shown in Table 1. With some reservations respecting the oil zone porosity determination, the Board has adopted the history matched hydrocarbons in place which are essentially the same as the previously established figures. The reservoir factors established by the Board are shown in Table 1.

DEFINITION OF TERMS

For convenience of referencing various pool operating schedules, the Board has adopted a code to show the gas cap cycling and gas sales schedules and the depletion mechanism. The code, C/S - X - C/S: CB or WF, where C is gas cycle rate, S is gas sales rate, X is the year up to, but not including that year, which the first C/S of the code is in effect, the second C/S becomes effective in the year X and CB denotes primary oil depletion cycle-blowdown while WF denotes water flood. All rates are in million cubic feet per day. Oil production rates are at prorated or productive capacity limits. Gas plant size may be, but not always, implied by the sum of the C/S figures.

The terms "liquid" and "liquids" as used in this report in discussing recovery of hydrocarbons from the reservoir include crude oil, condensate, propane and butanes.

Gas volumes noted, unless otherwise stated hereafter, are with acid gas present. Gas volumes or rates have approximately 4.5 per cent carbon dioxide included. The actual sales gas is free of acid gas and terms "marketable gas" or "pipe line gas" denote acid gas free volumes.

DEFINITION OF ISSUES

The Board believes that the application requires the consideration of the following matters:

(a) the desirability of water flooding the oil zone,

(b) the effect of the gas cycling and sales schedules on hydrocarbon recoveries, and

(c) conservation and economic considerations.

TECHNICAL STUDIES

Shell investigated alternative production methods for the pool by using both two dimensional (2-D) and three dimensional (3-D) model studies. Eight cases (I to VIII) were presented from the 2-D model studies and five cases, two of cycle-blowdown and three with water flood (CB1, CB2, WF1, WF2, WF3), from the 3-D model studies were submitted. Case WF3 is basically the depletion scheme which the applicant has asked the Board to approve. Two additional cases (WF4 and WF5), which were submitted at the Board's request, were prepared by using the results from WF1, WF2 and WF3 to determine the dependence of product recoveries on various gas cap operations. Shell contended that the results presented for these additional cases were consistent with results that would be obtained were model studies made. The Board is satisfied that these additional cases are suitable for making comparisons. A summary of the results, based on Shell's 3-D model studies, is presented in Table 2.

The 2-D model was used to examine the feasibility of oil recovery enhancement by water injection. An east-west vertical cross-section was selected to study the performance under various injection and production schemes. Assisted by the results from the 2-D model, an injection pattern was chosen for 3-D model predictions which Shell maintained was optimum and would achieve an acceptable level of pressure maintenance throughout the oil column. To further investigate the sensitivity of various water flood injection and production schemes, the Board staff has subsequently studied the same cross-section with a 2-D model. The results were similar to Shell's findings.

To assess the future performance of the cycling scheme and to adequately account for the vapourization effects of dry gas injection a model with compositional features was required. The 3-D model used by Shell was based on a partial density concept for a three-phase system of black oil, gas cap gas and injection gas. Shell stated that partial densities are determined on the assumptions that thermodynamic equilibrium exists in the reservoir, and that any component (methane, ethane, etc.) produced through a given set of surface separation conditions has the same distribution by weight in the surface products regardless of the reservoir phase from which it is produced. The developed relationships required for the partial density approach were compared to compositions obtained from laboratory analysis of the reservoir fluids. Adjustments to the relationships, none of which were major, were made as necessary to match the laboratory analysis. In support of the partial density approach, Shell stated that it has been used successfully in other instances

to investigate reservoirs with volatile fluids and cited examples where a similar 2-D, three-phase model had been employed. The model was judged by Shell to have yielded a satisfactory history match of production from the Harmattan East Rundle Pool, including 7 years of gas cap cycling. This, in Shell's opinion, indicated that the model had been used successfully to describe the compositional behaviour of the reservoir. On this basis the applicant concluded that the partial density, 3-D simulator could be used with a fair degree of confidence in the projection of future performances. Two cases under primary depletion (CB1 and CB2) and three cases under water flood conditions (WF1, WF2 and WF3) were forecast with the model.

The Board considers the history match obtained with the 3-D model to be good. Shell's discussion of various phases of the history match and the presentation of history matches for individual wells in the pool indicate the sensitivity of the model. The predictions obtained appear to be consistent and are considered reasonably reliable. In summary the Board is satisfied with most of the technical aspects of the application and agrees with Shell that a good degree of confidence can be placed in the model predictions. The Board adopts the recoveries predicted by the cases presented in Table 2 as a basis for discussion in this report.

The technical analysis provided by Shell did not show the effect of variations in plant size. The Board does not consider this to be a very significant variable in the analysis or in the decision and has used the plant size adopted by Shell in the analyses provided.

THE DESIRABILITY OF WATER FLOODING THE OIL ZONE

(1) Views of Shell

Shell submitted that declining pressures and increasing producing gas-oil ratios indicated the need for pressure maintaining the oil zone of the Harmattan East Rundle Pool. Its studies indicated that water flooding would improve recovery as shown in Tables 1 and 2 and that it was economically feasible to proceed. Also by maintaining crude oil productivity, the oil could be recovered sooner and permit the withdrawal of gas from the gas cap for sale.

After running two primary prediction cases, CB1 and CB2, the applicant used a 2-D east-west vertical cross-section to study various injection and production schemes. The purpose of the 2-D studies was to investigate how best to pressure maintain by water injection the central portion of the oil zone which is in direct communication with the gas cap.

To a large degree the oil zone is overlain by the gas cap. Eight predictions, all of ten years' duration, were run on the 2-D model. Case I was a base case, assuming concurrent depletion of the oil and gas zones with no water injection. It was characterized by rapid oil zone pressure decline, increasing gas-oil ratios and declining oil productivity. The other cases investigated concurrent depletion of the oil and gas zones under various water injection configurations. The results, which Shell considered more qualitative than quantitative, indicated that:

(a) water injection at the extreme updip edge of the gas-oil wedge zone was detrimental to oil recovery,

(b) water injection at the centre of the oil column, while providing effective sweep near the injector, failed to maintain pressure updip and downdip in the oil zone,

(c) two north-south rows of water injection wells provided better oil recovery than one central row, and by locating the rows on the downdip flank and the other some distance downdip of the edge of the gas-oil wedge zone the sweep of the oil zone was at a maximum, and

(d) two rows of water injection wells combined with gas cycling, wherein the gas injection point was near the updip edge of the gas-oil wedge, improved pressure maintenance, maintained productivity of the oil zone and retarded the eastward advance of the water front.

Shell concluded from the 2-D studies that the preferred water injection well pattern was two north-south rows of wells for the central portion of the main oil zone. The updip row should be located approximately in the centre of the oil zone and the downdip row should be along the western flank of the pool. This basic pattern was used in running the 3-D water flood cases. In the northern low production capacity portion of the main oil zone, a sufficient number of injection wells were chosen to provide a balance between water injected and oil produced. The southern portion of the main oil zone, being partially isolated from the gas cap on the east and partially cut off on the north by an erosional re-entrant, was considered amenable to a nine-spot injection well pattern. Shell expected one well would initially provide for the south salient water injection needs with another well added later in the life of the scheme. Three predictions were made with the 3-D model. WF1 and WF2, as shown in Table 2, had the same gas

sales and cycling schedules as CB1 and CB2 respectively. Shell contended that WF1 and WF2 illustrated the practical bounds of liquid recovery that could be achieved with a water flood-gas cycle-gas sales operation. The water flood oil recovery range shown in Table 2 was 35 to 41 per cent as compared to the primary depletion range of 26 to 30 per cent from the CB cases. WF3, with 30/125-79-0/125 demonstrated that with WF2's sales schedule and with some gas cycling adjacent to the oil zone, the oil recovery would be about 38 per cent or midway of the above range which Shell considered to be an appreciable increase over primary recovery.

Shell expressed concern that water injection would drive oil into the gas cap area and that eventual water movement into the gas cap could affect gas cap gas and liquid recovery. As was done in the 3-D model runs, Shell plans to designate the oil producers' updip of the central injectors as primary producers, insofar as producing gas-oil ratios would practically permit, so that maximum oil recovery of the wedge zone oil could be obtained. The concern for the effect of water moving into the gas cap, Shell contended, is offset by the incremental oil recovery to be achieved as compared to the gas cap loss that may occur. The potential oil recovery increment of 20 million barrels is far more significant than the possible gas cap losses as a result of the water flood scheme.

In spite of the fact that some of the oil wells have experienced high gas-oil ratios, Shell did not consider that fingering of injected water to producing wells would be serious. It did not specifically attribute the past excess gas production to channelling or coning but more to pressure drawdown within localized areas.

Basically Shell proposed to water flood the oil zone consistent with the scheme studied in Case WF3. Initially, water would be injected into 17 injection wells at approximately 35,000 barrels per day, rather than 24 injection wells as used in Case WF3. Shell proposed to monitor the performance of the scheme with 17 injectors and review the requirement for additional injection wells. The area of the proposed water flood scheme detailed in the application covers approximately 9600 acres. Some infill drilling in the south salient was proposed.

Shell proposed that the injection gas for the 30 million cubic feet per day cycling scheme be supplemented on a short term basis by 15 to 20 million cubic feet per day of gas produced from the oil wells which would further improve oil recovery. Considering this and the actual gas sales

commencement being one year later than assumed in Case WF3. Shell estimated the overall enhancement of oil recovery to be some 19 million barrels more than the 61 million barrels that would be recovered under continuation of the present primary depletion operation which is similar to Case CB1. Shell's reservoir factors for these recovery estimates are shown in Table 1.

Shell submitted that its studies had established that implementation of a water flood scheme in the oil zone with an injection of some 30,000 barrels of water per day would increase the pool oil recovery irrespective of the gas cap operations. Consequently its subsequent discussion centred mostly on the water flood cases.

(2) Views of the Board

The Board agrees with Shell that declining pressures indicate the need for pressure maintenance of the oil zone of the pool and generally agrees with Shell's proposed water flood scheme.

The Board studies confirm those of the applicant that an improvement in oil recovery can be achieved by injecting water. The Board has some reservation regarding the feasibility of recovering oil from the updip gas-oil wedge zone because of excessive gas coning. Typically, Rundle pools have shown poor performance in this respect. The Board is concerned that the injected water would have a negative effect on gas cap recoveries. The Board estimates that the maximum loss in gas recovery as a result of water encroachment to the gas cap area is 50 billion cubic feet. In terms of energy equivalent or in current dollar value the Board recognizes and accepts that the incremental oil recovery will more than offset the gas cap recovery losses.

It is recognized that continuation of gas cycling adjacent to the oil zone in conjunction with the water flooding would provide pressure support to the oil column and would significantly improve oil recovery.

The Board estimates that the water flooding could increase oil recovery by 12 to 20 million barrels depending on the blowdown date and the gas cycle/sales schedules selected. Table 1 shows a comparison of Shell's proposal and the Board's reserve estimates which are consistent with the decision on gas cycle/sales schedules.

The approval area proposed by Shell is considered by the Board to contain some tracts which do not have significant oil in place or which would not be swept under the scheme.

Although the approval area is not all composed of contiguous tracts, the Board believes a single project could be made for the approval area but would expect production and injection within isolated areas in the project to be appropriately balanced.

Shell's proposal to observe initial flood effects with 17 injection wells before deciding on the location of additional water injectors is satisfactory to the Board. With regard to other monitoring aspects of the water flood scheme performance, the Board believes a suitable minimum pressure to be maintained in the oil zone should be established, probably of the order of 2800 psig. Producing gas-oil ratio restrictions are considered unnecessary at this time. If used, gas-oil ratio restrictions would have to vary with specific areas of the oil zone. As discussed at the hearing, this matter will be considered with the applicant at a later date to reach a mutually suitable monitoring program.

The Board concurs with the applicant that recovery and economic considerations indicate that water flood operations should be instituted in the oil column of the Harmattan East Rundle Pool. Therefore all further discussions are based on the results of those cases predicted under water flood operations (Case WF1 to Case WF5).

THE EFFECT OF THE GAS CYCLING AND SALES SCHEDULES ON HYDROCARBON RECOVERIES

(1) Views of Shell

The applicant submitted several depletion schemes, based on its 3-D model, which showed the change of total hydrocarbons recoverable under various gas cycle/sales schedules. Shell contended that, without regard for total project economics, the liquid recoveries determined by Case WF1 (120/0-85-0/125) would be the practical maximum level of liquid recovery that could be achieved from the Harmattan East Unit Area with a water flood - gas cycling - gas sales operation. The blowdown date of 1985 for Case WF1 was chosen on the basis of reservoir performance predicted by the 3-D model. By 1985 the cumulative oil production would be 83 per cent of the predicted pool oil recovery, the condensate content of the cycled gas cap gas would have declined from an initial recovery of 42 barrels per million cubic feet to 8 barrels per million cubic feet and the gas cap wells would be producing in excess of 80 per cent dry gas. Shell stated that operation of the cycling scheme would still be economic at the aforementioned limits.

In order to compare final sales gas and gas cap liquid recoveries, Shell adjusted all cases to the same final abandonment pressure. Cases predicted from the 3-D model terminated at various abandonment pressures ranging from 1151 pounds per square inch absolute (psia) in Case CB2 to 1444 psia in Case WF1. Therefore all results were extrapolated to a common gas cap depletion pressure of 1100 psia by incrementing the forecast gas recovery at 1500 psia in each case by 150 Bcf which would be the average sales gas production for the 400 psi decline in the gas cap pressure. Gas cap liquid recoveries were also estimated by using the producing gas liquid content at 1500 psia and the above incremental sales gas volume of 150 Bcf. Although 1100 psia would likely not be the final reservoir abandonment pressure it was considered by the applicant to be a good reference point for both recovery and economic comparative purposes.

Referring to Table 2, a comparison of Cases WF1 and WF2 illustrates the dependence of liquid recovery upon blowdown date. Both oil and gas cap liquid recovery would decline with early gas sales while marketable gas recovery would increase somewhat. Total hydrocarbon liquid recovery would range from 126.7 million barrels when blowdown commences in mid-1972 to 147.7 million barrels if blowdown were initiated in 1985. By continuing cycling and deferring blowdown for 12.5 years, an additional 21.0 million barrels of liquid would be recovered. The applicant expressed the opinion that additional liquid recovery attainable by deferring blowdown beyond 1985 would be minimal.

The applicant contended that the potential risk to gas recovery as a result of water injection into the oil column would be reduced by cycling some gas adjacent to the oil zone and by depleting the gas cap as rapidly as practicable. The adverse effects of early full contract gas sales (Case WF2) on liquid recovery would be, to a large degree, offset by limited gas cycling adjacent to the oil column. Case WF3, with a 30/125-79-0/125 schedule, was presented as an example of the cycling effect on recovery. The applicant compared Case WF3 to the boundary cases, Case WF1 and Case WF2. During the 6.5 year period (mid-1972 to 1979) of continued cycling in Case WF3, a total of 77 Bcf of gas would be cycled with the result that total hydrocarbon liquid recoveries would be increased by some 9.2 million barrels over Case WF2. This compares with Case WF1 where an additional recovery of 21.0 million barrels over Case WF2 would be obtained after cycling 560 Bcf during a 12.5 year period (mid-1972 to 1985). In other words, to obtain the additional 11.8 million barrels between Case WF3 and Case WF1, an additional 483 Bcf of gas must be cycled. Based on this performance, Shell concluded that the liquid recoveries would show an exponential

relationship as the cycling conditions of Case WF1 were approached. This relationship is illustrated for natural gas liquid recoveries in Figure 6, which was taken from Shell's application.

Shell stated that cycling was continued in Case WF3 until gas cap deliverability problems were encountered. At this point, further cycling would become impractical as the loss in present worth income that would result from a decrease in the gas sales rate would not be offset by the revenue generated by the additional liquid recovery from the cycled gas. Shell maintained that this was essentially the basis for terminating cycling after 1978.

The applicant has basically proposed a schedule based on Case WF3 (30/125-79-0/125) which it states would offset the reduction in liquid recovery due to early gas sales (Case WF2, 120/0-72-0/125) by approximately one-half. As Table 2 shows, the pool total hydrocarbon liquid recovery for Case WF3 would be 12 million barrels less than the practical maximum defined by Case WF1 (120/0-85-0/125). This figure would become 10 million barrels if the proposed supplemental solution gas injection and delayed start of actual gas sales noted earlier under the water flood discussion are taken into account.

Table 2 shows Cases WF4 and WF5, which were supplied at the Board's request, demonstrating how variations of the gas sales schedule with a corresponding variation in the cycle schedule, 125/30-79-0/125 and 95/60-79-0/125 respectively, would affect liquid recovery. Post mid-1972 cycle volumes of some 300 BCF and 230 BCF result in total liquid recoveries of 144.0 and 142.2 million barrels for Cases WF4 and WF5 respectively compared to 77 BCF cycled for a total liquid recovery of 135.9 million barrels in Case WF3. Liquid recoveries would be 3.7 million and 5.5 million barrels less for Cases WF4 and WF5 respectively than the practical maximum of 147.7 million barrels for Case WF1.

(2) Views of the Board

The Board generally agrees with Shell's estimates of liquid and gas recovery at the reference abandonment pressure of 1100 psia used by Shell for the cases presented. It believes further recoveries, particularly with respect to gas cap gas, will be achieved beyond the assumed abandonment pressure but agrees that 1100 psia is a good reference point for recovery and economic comparisons. The Board acknowledges Shell's view that, when the water injected into the oil column encroaches on the gas cap area, the rate of gas cap depletion

could have an effect on gas recovery. It believes this should be reviewed and considered in the later life of the scheme when some performance data are available. The Board accepts that the results of Case WF1 and Case WF2 provide a practical range of recoveries that could be achieved with a water flood-gas sales operation. Using the liquid and gas recoveries determined by these two cases, the Board prepared Figure 1 to illustrate qualitatively the effect of blowdown deferment on recovery. The Board appreciates that the curvature of the recovery lines is interpretive, however the studies clearly show that liquid recoveries would increase with deferment of blowdown but that the rate of increase would decline as a function of time. Thus, in general, from a recovery point of view, blowdown should be deferred as long as possible.

Using data from Table 2 the table below was prepared to illustrate the incremental losses in recovery of various cases relative to the practical maximum liquid recovery, Case WF1, 120/0-85-0/125:WF.

Incremental Recovery Loss Relative to Case WF1
(million barrels)

	WF2	WF3	WF4	WF5
Oil	11.4	6.0	2.0	3.0
Oil-field condensate	3.0	3.4	N/A	N/A
Plant condensate	2.1	0.0	N/A	N/A
Total condensate	5.1	3.4	1.0	1.5
Propane	3.0	1.8	0.5	0.7
Butane	1.5	0.6	0.2	0.3
Total liquids	21.0	11.8	3.7	5.5
Gas sales, BCF	-35	-75	-40	-45

Figures in the table show that immediate blowdown, Case WF2, 120/0-72.5-0/125:WF, would result in a loss of 21.0 million barrels of liquid recovery relative to the practical maximum of 147.7 million barrels of a 1985 blowdown with continued cycling. Further, of the 21.0 million barrels, 11.4 million barrels or 54 per cent would be a crude oil recovery loss. Adding to this some oil zone derived natural gas liquid which would also be lost, an estimated 60 per cent of the loss in liquid recovery as a result of gas cap blowdown can be attributed to the associated oil zone. As Figure 1 illustrates the marketable gas recovery decreases slightly with deferment of blowdown. Some 35 BCF of sales gas could be gained by immediate blowdown but this is small relative to the 21 million barrels of liquid loss. Also the decrease in gas recovery must not be considered to be entirely disadvantageous, because

at a given final reservoir pressure it is better to have the pore space occupied by dry gas rather than by liquids or wet gas. From this analysis the Board concludes that blowdown of the gas cap affects the recovery of the oil zone liquids somewhat more adversely than the gas cap liquids.

As Shell contended and as the above tabulation of incremental recovery losses of Cases WF3, WF4 and WF5 relative to Case WF1 illustrates, the adverse effects of early blowdown and gas sales rates could be partially offset by cycling gas cap gas adjacent to the oil zone. Increased recovery of all liquids and sales gas would be achieved in the cases demonstrated. It is difficult to quantify the magnitude of the effect of cycling and sales gas schedules on recoveries as separate entities. However, Figure 2 provides some insight on the effect of each on recovery.

Figure 2 was prepared by the Board to illustrate the relationship of liquid recovery and the gas cycle/sales schedule for depletion schemes involving a water flood operation. The recoveries as predicted by Cases WF1 through WF5 were plotted and the curvature of the liquid recovery lines was estimated with the limited data available. Data points shown for blowdown commencing in 1979 with cycling rates of 30, 95 and 125 million cubic feet per day have, because of a fixed plant size of 155 million cubic feet per day, complementary sales rates of 125, 60 and 30 million cubic feet per day respectively. Thus, the figure demonstrates implicitly the degree to which complementary cycle/sales schedules affect recovery along with an indication of the magnitude of recovery improvement resulting from deferment of blowdown for various gas schedules.

It is apparent from Figure 2 that alternative gas cycle/sales schedules can yield the same liquid recovery. For example, a total recovery of approximately 142 million barrels may be obtained by a sales schedule of 95/60-79-0/125 (Case WF5), a schedule of 125/30-77-0/125 or a schedule of 125/0-76-0/125.

To further clarify the relationship of cycling rate, hydrocarbon liquid recovery and blowdown time, the Board prepared Figure 5. This figure incorporated Figure 6 which illustrated the dependence of post mid-1972 gas liquid recovery on post mid-1972 cumulative cycled gas. The Board noted that total hydrocarbon liquid recovery showed a similar dependence upon volumes of cycled gas. It thus believes that the idea presented in Figure 6 can be extended within a limited range to include total hydrocarbon liquid recovery for purposes of estimating recoveries under alternate cycling/sales schedules. Using the parameters of cycling rate (C) and

time (T), lines of constant cycled gas volumes (C x T = Constant were plotted on Figure 5. The cycled gas volumes are cumulative after mid-1972 and the time represents years after mid-1972. Within a limited range and based on the results of Figure 6, a line of constant cycled gas volume should also represent a constant liquid recovery post mid-1972. Based on the production schedules submitted by Shell, the Board believes that cycling operations for Case WF3 could be continued throughout 1979 before gas cap deliverability problems would be encountered. Using the gas cap voidage as calculated for Case WF3 at 1980, deliverability limits were estimated for alternate cycling/sales schedules. This is shown in Figure 5. The Board believes this deliverability cut-off line can be used to limit the area of investigation when examining the merits of alternate cycling/sales schedules. The figure demonstrates the various cycling rate-blowdown schedules possible for a fixed liquid recovery. It also illustrates the magnitude of liquid recovery improvement obtained by

(a) increasing the cycling rate for a given year of blowdown, and

(b) deferring blowdown for a given cycling rate.

For example, to obtain a total liquid recovery of 142.2 million barrels an additional 225 Bcf of gas must be cycled after mid-1972. This could be accomplished by the cycling/sales schedules of 95/60-79-0/125, 72/83-81-0/125 and 58/97-83-0/125. It also illustrated that if the cycling/sales schedule is fixed at 95/60-X-0/125, an additional 1.8 million barrels of liquids could be obtained by deferring blowdown for two years as shown by comparing schedules 95/60-79-0/125 and 95/60-81-0/125. If the blowdown date is fixed at 1979 for example, an additional 1.8 million barrels of liquids could be recovered by using a higher cycling rate schedule of 125/30-79-0/125 as compared to a schedule of 95/60-79-0/125.

The above analysis demonstrates the degree to which continued gas cycling could offset some of the losses in recovery arising out of the early blowdown of the gas cap. More than half of these losses occur in the oil zone which is to be expected since the blowdown of a gas cap would reduce oil recovery. In general the Board does not countenance the blowdown of gas caps except under marginal economic circumstances or where the recoverable oil reserve and possible losses are modest in absolute magnitude. This policy also applies to the production of gas caps where significant retrograde losses could occur as a result of blowdown. Having regard for this policy and the detailed model studies of the Harmattan East Rundle Pool, the Board concludes that gas sales should be permitted only if the resultant recovery loss is a

minimum. The studies show that this objective could be attained by continuing to cycle gas at a relatively high rate and by limiting gas sales.

CONSERVATION AND ECONOMIC CONSIDERATIONS

(1) Views of Shell

Shell provided a detailed economic analysis for each of the seven prediction cases. Cash flow and present worth were presented to demonstrate the effect of various operational programs on conservation and economics. The analysis compared "Base Economics" based on "today's costs and product prices" with "Board Escalated Economics" as used by the Board in Decision 71-12[1] and "Shell Escalated Economics" based on Shell's estimateof escalation factors. The applicant provided present worth at both 8 and 10 per cent discount rates. It used the latter rate in its discussions.

The applicant compared the three sets of economics considered. The applicant's economics and recoveries are presented in Table 3. Although the escalated economics indicate an overall increase in the total scheme present value for each case investigated, the order of the cases relative to each other is the same in each set of economics considered. The incremental profits before taxes are approximately the same for each set of economics. Therefore Shell contended that the decision with respect to future operations on the Harmattan East Unit No. 1 area is essentially independent of whether nonescalated or escalated economics are used.

Shell's proposed scheme would return a present value profit before taxes (PVPBT), at a 10 per cent discount rate, of approximately 111.7 million dollars and a liquid recovery of 138 million barrels. As shown in Table 3, a maximum liquid recovery of 147.7 million barrels could be obtained by Case WF1, 120/0-85-0/125 which returns a PVPBT, discounted at a rate of 10 per cent, of approximately 80.3 million dollars. Although Case WF1 would yield a better total liquid recovery than the proposed scheme, Shell considered 31.4 million dollars loss in present value to recover an additional 10 million barrels of liquid, or a present value cost of 3.14 dollars per barrel, as too much having regard for current product prices and finding costs. The latter was quoted to be in the order of 1.10 to 1.15 dollars per barrel. Considering the level of

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(1) Decision 71-12: Concurrent Production of the Oil Zone (Application No. 5396) and Gas Cap with Gas Cap Cycling and Partial Water Flooding of the Oil Zone - Harmattan Elkton Rundle C Pool.

recovery that would be achieved by the proposed scheme relative to the maximum practically attainable and having regard for the significant decrease in PVPBT that would be incurred if the maximum recovery scheme were implemented, Shell contended that the proposed scheme would be consistent with good economic conservation.

The applicant stated that on a total energy basis, recovery from the pool would be maximized by the proposed scheme in that Case WF3 would provide products with an energy equivalent of 1574×10^{12} British Thermal Units (Btu) compared to 1563×10^{12} Btu for Case WF1. Case WF4 and WF5 would provide 1587×10^{12} and 1583×10^{12} Btu respectively.

(2) Views of the Board

The Board believes that in assessing the economic implications of any scheme, it must recognize to some degree the probability of future price increases for petroleum products and increasing operating costs. In addition, it believes that in this application a present worth discount rate of 8 per cent is appropriate for the economic evaluations. The applicant supplied supplemental economic information that incorporated a discount rate of 8 per cent and employed escalation factors (based on Decision 71-12) for product prices and operating costs. The Board believes the escalation factors used for the sales gas are somewhat low. However it has determined that the discounted cash flows using higher sales gas prices do not significantly change the relative economics of the cases studied. Considering the present uncertainty of future gas pricing, the Board has decided to evaluate the economics based on the supplemental information submitted by Shell for "Board Escalated Economics".

Figure 3 illustrates the present worth associated with various gas cycle/sales schedules based upon the assumed prices and costs for the WF Cases. The lower curve shows the present worth assuming no gas sales prior to blowdown. The data for the other cases with gas sales prior to blowdown are limited but the impact on present worth is roughly illustrated for 125/30-X-0/125, 95/60-X-0/125 and 30/125-X-0/125 schedules for the period 1979 to 1983.

The lower curve in Figure 3 clearly demonstrates the unfavourable impact on present worth of deferring blowdown. The figure also illustrates the substantial improvement in present worth achieved by permitting gas sales while cycling operations continue.

Figure 4 combines the physical recovery and present worth projections of Figures 2 and 3 for the 120/0-X-0/125 schedule

and shows the recovery and present worth estimates for the 125/30-79-0/125, 95/60-79-0/125 and 30/125-79-0/125 schedules. As stated previously, the deferment of blowdown to 1985 would provide the highest liquid recovery of 147.7 million barrels but the lowest present worth of 116.9 million dollars. While this scheme would result in an ideal level of recovery, the Board agrees that the costs involved would be excessive.

The proposed 30/125-79-0/125 case, despite yielding an improvement in recovery of 9.2 million barrels over the immediate blowdown case of 120/0-72.5-0/125 and an improvement in present worth of 11.0 million dollars, recovers 11.8 million barrels (or 10 million barrels by Shell's actual proposal) less than the practical maximum case of 120/0-85-0/125. Somewhat more than 6 million barrels of the 11.8 million barrel loss originates in the oil zone and in essence is caused by the proposed gas sales.

As noted earlier, recovery may be improved by increasing the cycling rate and decreasing the sales rate. In Case WF5, having a 60/95-79-0/125 gas schedule, total liquid recovery is increased by 6.3 million barrels of which more than 3.0 million barrels is attributable to the oil zone. This schedule would result in oil zone losses of some 3.3 million barrels as compared to the practical maximum recovery case. This loss represents about 4.0 per cent of the recoverable oil.

Case WF4 having a 125/30-79-0/125 gas schedule provides a further improvement in recovery of some 1.8 million barrels of which 1.0 million is attributable to the oil zone. The oil zone losses associated with this schedule would be some 2.2 million barrels or less than three per cent of the recoverable oil.

Correspondingly, Cases WF5 and WF4 show a progressive increase in cash flow but a progressive decrease in present worth of 134.1 and 131.0 million dollars respectively. The present worth is considerably better for each case than that of Case WF1, 120/0-85-0/125 which is 116.9 million dollars and compares favourably with Case WF2, 120/0-72.5-0/125, at 134.3 million dollars. There is, however, a decrease of some 11-14 million dollars over the proposed case.

The Board believes that the losses in oil recovery caused by blowdown of the gas cap as proposed by the applicant are incompatible with its basic policy regarding the blowdown of gas caps and are therefore not acceptable. The losses associated with Case WF5 also appear somewhat excessive while those associated with Case WF4 appear to be acceptable. The Board concludes that the level of recovery obtainable by Case WF4 is

desirable. The Board recognizes that this level of recovery could be obtained by different gas schedules, having varying cycling rates, sales rates and blowdown dates as illustrated in Figure 5. In general, the Board believes that the cycling rate should be as high as practical whereas the sales rate should be as low as practical. It appears to the Board that the gas cycling rate should not be less than 90 million cubic feet per day and the sales rate should not exceed 65 million cubic feet per day. In order to achieve the desired total liquid recovery, this cycling/sales combination would remain in effect until around 1981 to 1982.

The Board acknowledges Shell's views on the total energy equivalent basis for comparing the WF Cases. Because of the relatively small differences in the total energy equivalent figures among the cases the Board did not make a detailed analysis of the matter. The Board does note however that there is a significant difference in price of gas and oil Btu equivalent and believes that this factor would have to be considered in such an analysis.

The Board is prepared to approve a gas schedule providing for the immediate sale of gas at a rate of 60 million cubic feet per day free of acid gas and for the continuation of cycling operations at 90 million cubic feet per day until about 1981 to 1982 following which gas sales at a rate of about 125 million cubic feet per day may be permitted. The Board believes that it would be better to determine the precise date of blowdown and the precise final sales rate following an assessment of the results of operations after a few years.

DECISION

The Board grants approval of a scheme of production of oil and gas from the Harmattan East Unit No. 1 area of the Harmattan East Rundle Pool as follows:

1. The oil accumulation and its associated gas cap may be concurrently produced in accordance with Board Approval No. 1762 being issued simultaneously with this decision.

2. Annual gas sales, which may commence about November 1, 1973, shall not exceed 21.9 billion standard cubic feet of pipe line gas and shall be produced from the wells as set out in Board Approval No. 597 at daily maximum rates as approved by the Board.

3. Gas cycling of the gas cap adjacent to the oil accumulation at an average annual injection rate of 90 million cubic feet per day in accordance with Board Approval No. 597 and

amendments approved by the Board shall continue until about 1981 to 1982 following which cycling may be terminated and gas sales could increase to about 125 million cubic feet per day, the precise year and final sales rate to be determined following assessment of performance and an application to the Board.

4. The oil accumulation shall be pressure maintained by the injection of water in accordance with Board Approval No. 1761 being issued simultaneously with this decision.

5. The crude oil reserves established for the pool in accordance with the approved scheme are as shown in Table 1 under the column "Board", the primary recovery being effective July 1, 1972, and the water flood increment being effective when the scheme qualifies for enhanced recovery recognition.

ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard

Vernon Millard
Vice Chairman

DATED at Calgary, Alberta
June 2, 1972

ENERGY RESOURCES CONSERVATION BOARD

TABLE 1 TO DECISION 72-5

HARMATTAN EAST RUNDLE POOL

COMPARISON OF OIL AND GAS ZONE RESERVOIR PARAMETERS AND RESERVES FROM SHELL SUBMISSION AND AS ESTABLISHED BY THE BOARD

PARAMETER	SHELL	BOARD
A. OIL ZONE		
OIL ZONE ROCK VOLUME (ACRE-FEET)	342,000	(340,000)
AREA (ACRES)	-	11,500
THICKNESS (FEET)	-	(29.6)
POROSITY	.137	.137
WATER SATURATION	.849	.85
SHRINKAGE	.67	.67
OIL IN PLACE (MILLION STB)	206*	206
PRIMARY RECOVERY FACTOR	(0.295)**	.32
PRIMARY RECOVERY (MILLION STB)	60.7	65.9
RESIDUAL OIL SATURATION	.35	.35
AREAL SWEEP EFFICIENCY	-	.80
VERTICAL SWEEP EFFICIENCY	-	.84
INCREMENTAL WATERFLOOD RECOVERY FACTOR	(0.093)	.08
INCREMENTAL WATERFLOOD RECOVERY (MILLION STB)	19.3***	16.5
TOTAL RECOVERY (MILLION STB)	80.0	82.4
RFM (WATERFLOOD)	-	1.25
B. GAS ZONE		
GAS IN PLACE (BCF)		
HARMATTAN EAST RUNDLE POOL	-	1,110
SOUTHERN SEGMENT (HARMATTAN EAST UNIT NO. 1)	900*	900
SOLUTION GAS	230*	200
MARKETABLE GAS (BCF)		
HARMATTAN EAST RUNDLE POOL	-	830
SOUTHERN SEGMENT (HARMATTAN EAST UNIT NO. 1)	740**; 800***	670
SOLUTION GAS		100

* 3-D PARTIAL DENSITY MODEL HISTORY MATCH

** CASE CB1

*** CASE WF3 SUPPLEMENTED BY AN ADDITIONAL 2 MILLION STB AS A RESULT OF 15 TO 20 MMCFD GAS INJECTION OVER AND ABOVE THE 30 MMCFD CYCLE GAS

ENERGY RESOURCES CONSERVATION BOARD

TABLE 2 TO DECISION 72-5

SUMMARY OF RECOVERIES

HARMATTAN EAST RUNDLE POOL

(ALL RECOVERY VALUES IN MMBBL OR BCF, SCHEDULES IN MMCFD)

CASE	CB1	CB2	WF1	WF2	WF3	WF4	WF5
GAS CYCLING/GAS SALES SCHEDULE*	120/0-85-0/125	120/0-72.5-0/125	120/0-85-0/125	120/0-72.5-0/125	30/125-79-0/125	125/30-79-0/125	95/60-79-0/125
OIL RECOVERY (FRACTION)	.295	.262	.407	.352	.378	.397	.392
OIL	60.7	54.1	83.8	72.4	77.8(80)***	81.8	80.8
OIL-FIELD CONDENSATE	15.4	10.1	6.6	3.6	3.2		
PLANT CONDENSATE	21.5	20.7	26.2	24.1	26.2		
TOTAL CONDENSATE	36.9	30.8	32.8	27.7	29.4	31.8	31.[illegible]
PROPANE	24.0	18.4	18.6	15.6	16.8	18.1	17.9
BUTANE	15.2	12.5	12.5	11.0	11.9	12.3	12.2
TOTAL LIQUIDS	136.8	115.8	147.7	126.7	135.9(138)***	144.0	14[illegible]
SALES GAS (1100 PSIG A&N)	775(740)**	820(785)**	765(730)**	800(765)**	840(800)**	805(770)**	[illegible](775)**

* SCHEDULE VOLUMES INCLUDE ACID GASES.

** RECOVERIES FROM MCCORD REPORT REDUCED BY 4.5% TO ACCOUNT FOR REMOVAL OF CO_2 IN BRACKETS.

*** FIGURES IN BRACKETS ARE SHELL'S ESTIMATE CONSIDERING SUPPLEMENTAL GAS CYCLING INCLUDED IN FINAL PROPOSAL AND A LATER START ON GAS SALES THAN MID-1972.

ENERGY RESOURCES CONSERVATION BOARD

TABLE 3 TO DECISION 72-5

SUMMARY AND COMPARISON OF RECOVERIES AND ECONOMICS OF CASES STUDIED
HARMATTAN EAST RUNDLE POOL

		ECONOMICS - $ MILLION									RECOVERY		
		Cash Flow			Present Worth 8% Discount			Present Worth 10% Discount			Total Liquid Recovery	Sales** Gas	Energy Equivalent
Case	Board Code	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)	MM Bbl	Bcf	Btu 10^{12}
CB1	120/0-85-0/125:CB	247.1	247.2	330.3	86.0	91.1	104.3	72.1	76.6	85.4	136.8	740	-
CB2	120/0-72.5-0/125:CB	223.3	226.3	260.6	117.2	122.0	130.1	103.3	107.7	113.6	115.8	785	-
WF1	120/0-85-0/125:WF	254.6	268.1	336.1	95.8	105.8	116.9	80.3	89.0	96.3	147.7	730	1563
WF2	120/0-72.5-0/125:WF	228.5	232.8	268.7	120.8	127.9	134.3	106.8	113.2	117.8	126.7	765	1491
WF3	30/125-79-0/125:WF	252.0	263.2	300.5	129.3	138.6	145.3	113.7*	121.9	126.5	135.9*	800	1574
WF4	125/30-79-0/125:WF	261.6	-	322.9	113.6	-	131.0	97.0	-	110.6	144.0	770	1587
WF5	95/60-79-0/125:WF	255.7	-	311.2	118.6	-	134.1	102.1	-	114.5	142.2	775	1583

(1) Shell Base Economics
(2) Shell Escalated Economics
(3) Board Escalated Economics (Decision 71-12)
* In its proposed scheme Shell called the present worth 111.7 million dollars because of delay in actual start in scheme and the liquid recovery 138 million barrels as noted in Table 2.
** Acid gas free volumes

Note: Recoveries and economics are based on depletion of the reservoir to 1100 psia.

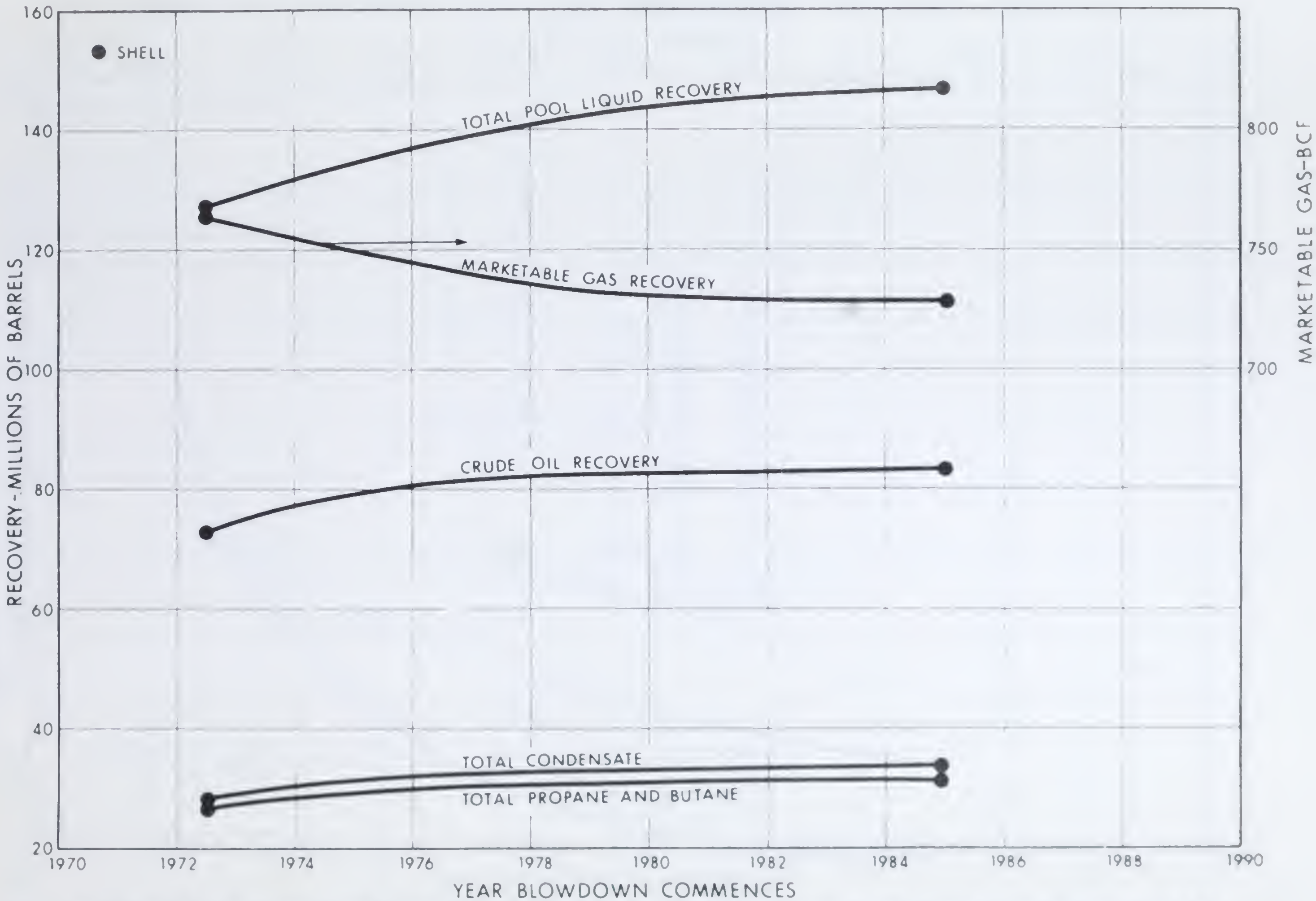

FIGURE 1 TO DECISION 72 - 5 -EFFECT OF BLOWDOWN TIME ON LIQUID RECOVERY
120/0-X-0/125: WF CASES
HARMATTAN EAST RUNDLE POOL

ENERGY RESOURCES CONSERVATION BOARD
CALGARY ALBERTA

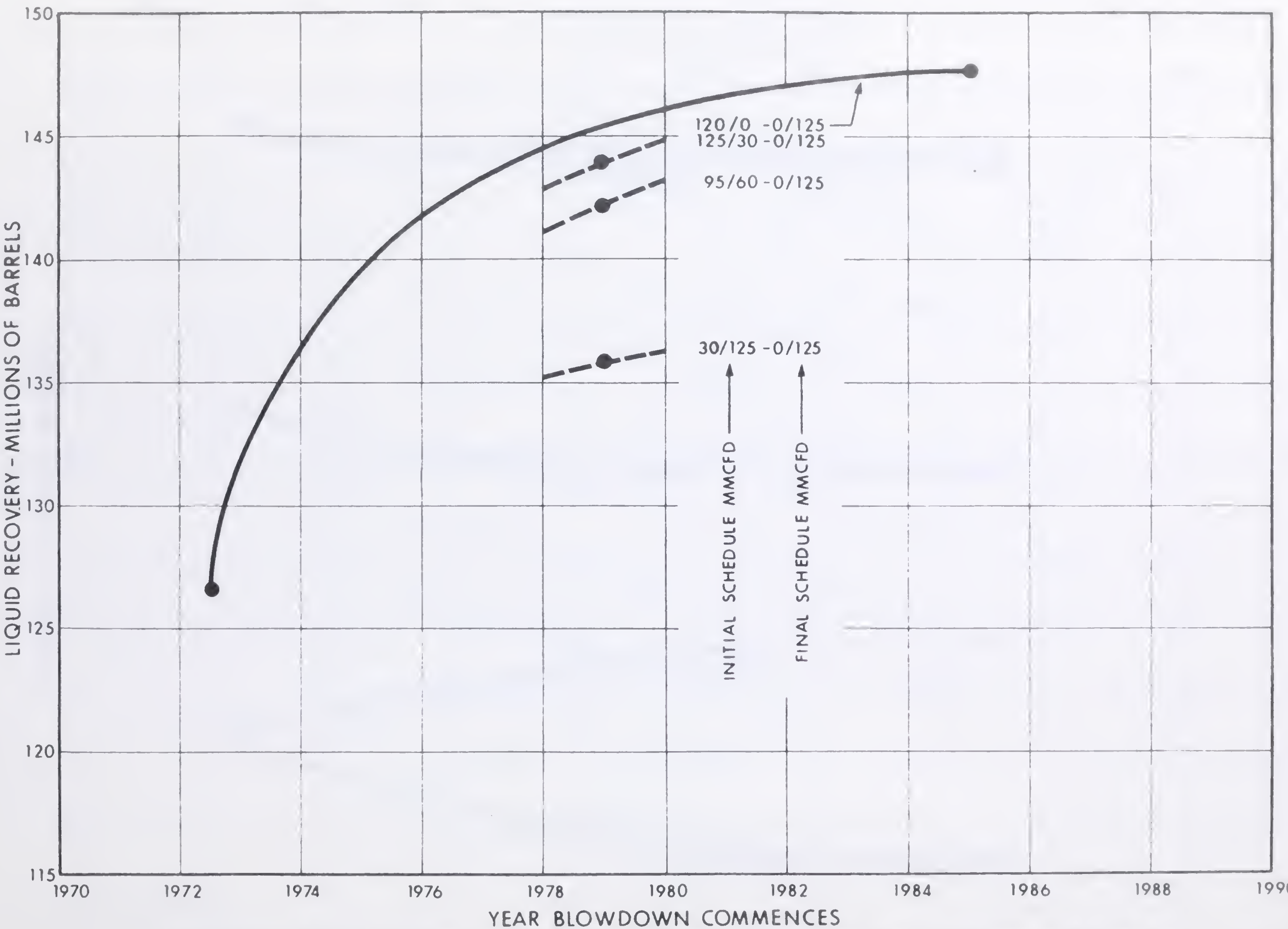

FIGURE 2 TO DECISION 72 - 5 - THE RELATIONSHIP OF LIQUID RECOVERY AND THE GAS CYCLE/SALES SCHEDULE

C/S - X - C/S: WF CASES

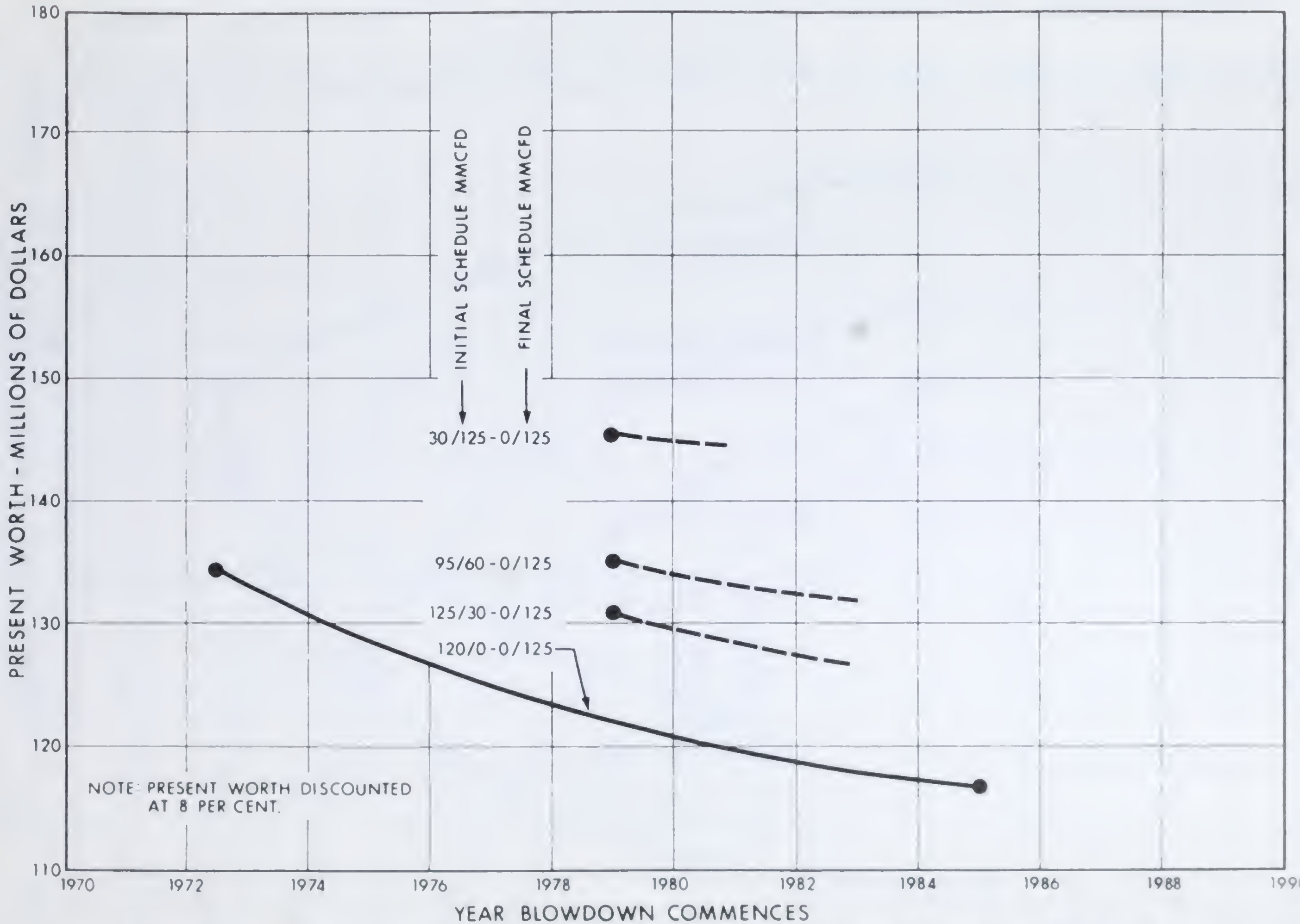

FIGURE 3 TO DECISION 72 - 5 - THE RELATIONSHIP OF PRESENT WORTH AND THE GAS CYCLE/SALES SCHEDULE

C/S - X - C/S: WF CASES

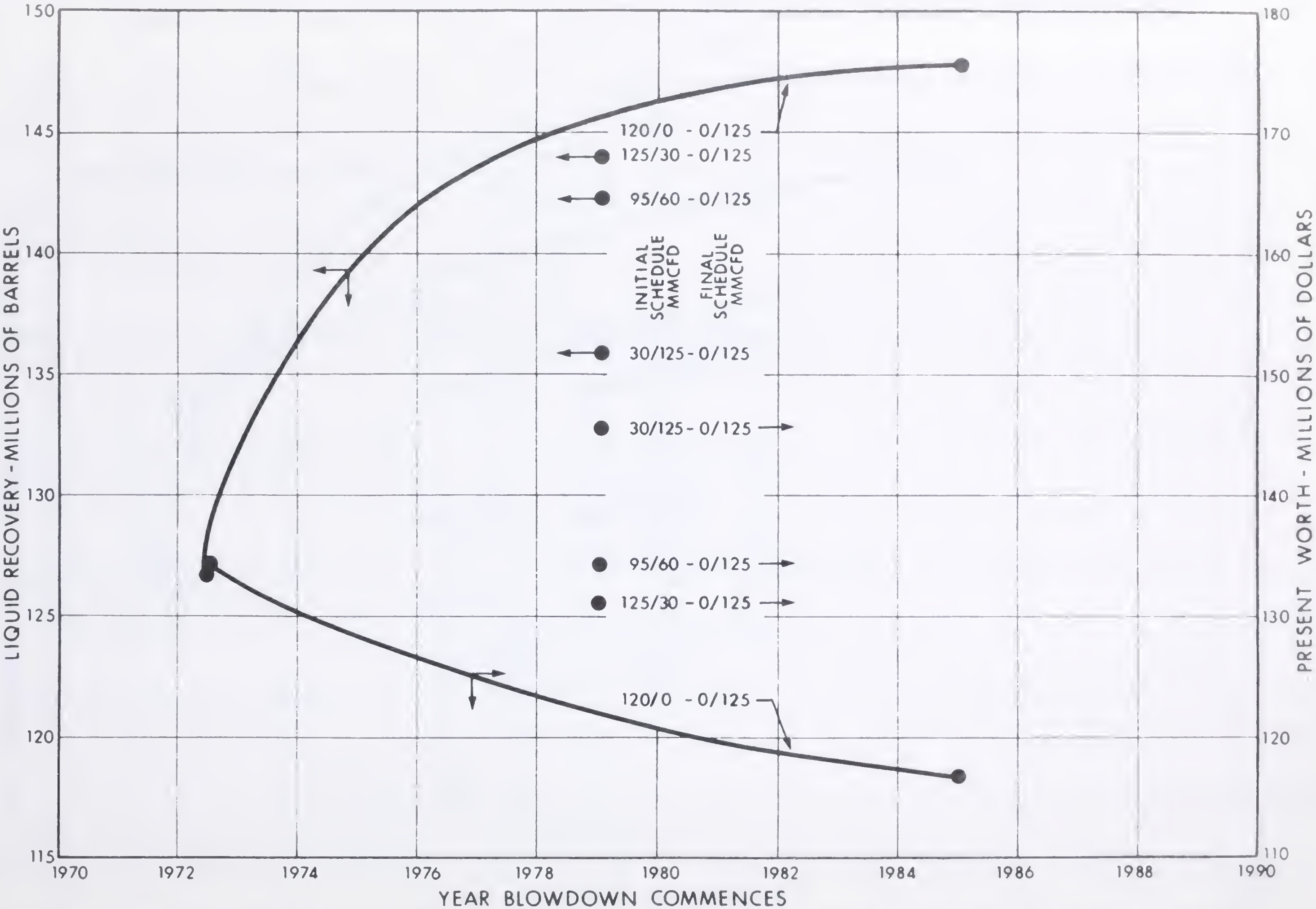

FIGURE 4 TO DECISION 72 - 5 - THE RELATIONSHIP OF RECOVERY, PRESENT WORTH AND THE GAS CYCLE/SALES SCHEDULE

C/S - X - C/S: WF CASES

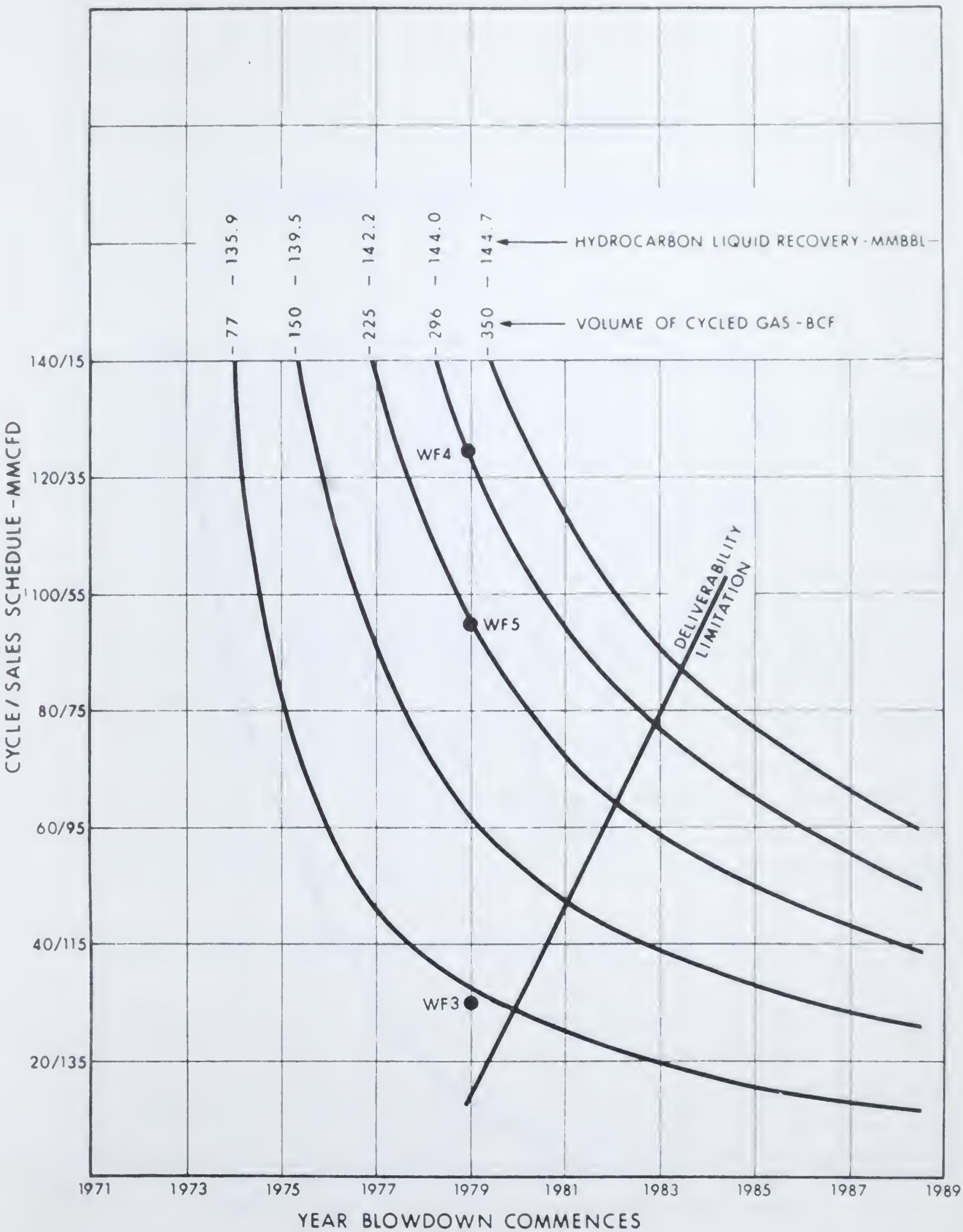

FIGURE 5 TO DECISION 72 - 5 - THE RELATIONSHIP OF LIQUID RECOVERY AND THE VOLUME OF CYCLED GAS

C/S-X-C/S: WF CASES

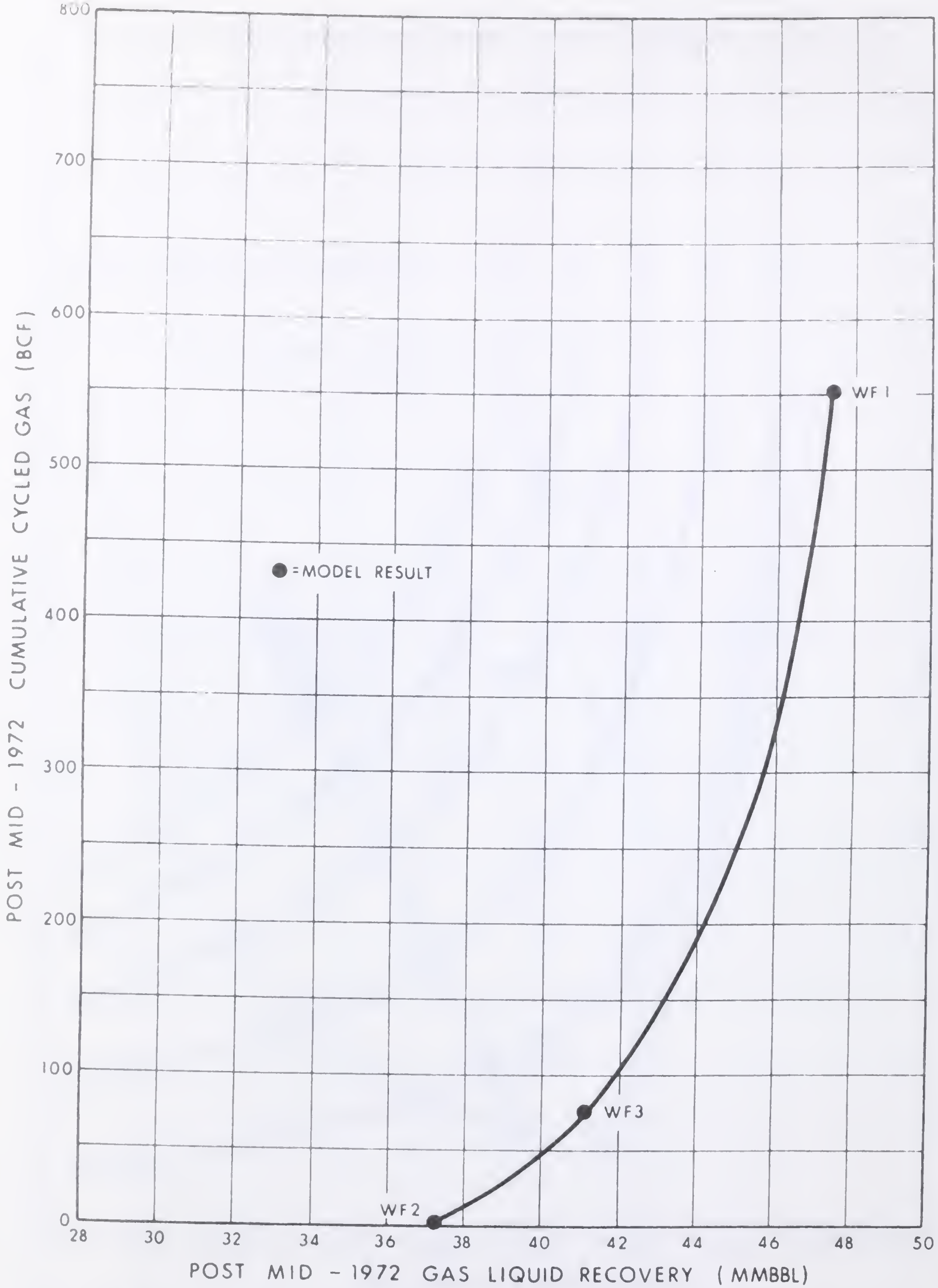

FIGURE 6 TO DECISION 72-5 - EFFECT OF CYCLING ON RECOVERY OF GAS LIQUIDS

APPLICATION NO. 6116 - SHELL

ATTACHMENT 3 OF EXHIBIT 5

ENERGY RESOURCES CONSERVATION BOARD

Decision 72-6
Application No. 6289

TRANSMISSION LINE - GRANDE PRAIRIE

INTRODUCTION

The subject application was made under section 13 of The Hydro and Electric Energy Act by David Thiessen and Mrs. David Thiessen who live one mile east of the City of Grande Prairie on the South-west quarter of Section 20, Township 71, Range 5, West of the 6th Meridian (hereinafter referred to as "the South-west quarter"). They applied for a direction requiring the relocation of part of the Alberta Power Limited (hereinafter called "Alberta Power") transmission line being erected between Grande Cache and Grande Prairie, in the neighbourhood of the South-west quarter.

A hearing of the application was set down to be held in Edmonton on April 26, 1972. At that time the hearing was adjourned and subsequently held at Grande Prairie on May 9, 1972, by Vernon Millard, Vice Chairman and J. I. Strong, P.Eng., Board Member.

The following appeared at the hearing:

	Represented by	Witnesses
David Thiessen and Mrs. David Thiessen	D. M. Willis (of Gauk & Willis)	David Thiessen W. R. Neufeld D. A. Thompson
Alberta Power Limited	B. V. Massie, Q.C. (of Milner & Steer)	D. J. Flory D. A. Peterson, P.Eng.
Board Staff	N. A. Macleod, Q.C. C. J. Goodman, P.Eng.	

Before the Board was given jurisdiction with respect to transmission lines with the coming into force of The Hydro and Electric Energy Act on June 1, 1971, the Grande Cache to Grande Prairie transmission line had been approved by the Alberta

Power Commission. Consequently, and by virtue of section 35 of the Act, on February 3, 1972, Alberta Power was in the position of being deemed to be the holder of a subsisting permit to construct and licence to operate the transmission line. On that day the Board issued Permit and Licence No. AP 72-2 to so formalize Alberta Power's position that it could apply under The Right of Entry Arbitration Act for an order enabling it to enter upon the subject and other lands for the construction of the transmission line.

The location of the part of the transmission line in the neighbourhood of the applicants' lands is shown on the appendix to this decision, which substantially is adapted from the map included in Alberta Power's intervention. It is noted that following the right of way of the transmission line northward, it is close to the western edge of Wood Lake and immediately east of the South-west quarter until it reaches a point approximately 850 feet south of the North-east corner of the South-west quarter where it turns to avoid interference with an air strip and crosses the South-west quarter. The right of way then turns north just within the western boundary of the South-west quarter.

The main points in the applicants' submission are that the subject right of way parallels at a distance of a half a mile an existing transmission line right of way which could be expanded to carry two transmission lines; that the applicants have two power lines located on their land at the present time; that the right of way crosses a natural nesting ground for trumpeter swans; that the right of way adversely affects the usefulness and amenities of the appellants' lands; and that Alberta Power chose the right of way after negotiating with the applicants on two alternative routes, but without negotiating or advising the applicants as to the right of way finally applied for.

Alberta Power in its intervention contended that agreement as to the route and compensation could not be obtained; that the transmission of electric energy from Grande Cache to Grande Prairie is necessary in the public interest; that relocation to a location west of the right of way is impractical in the light of present and prospective development in the area; and that the line was chosen as entailing the least inconvenience to the least number of land owners in the area. Dealing in argument with the last point in its submission Alberta Power pointed out that section 13 of the Act authorized the Board to direct the relocation of a transmission line only where "the alteration or relocation would be in the public interest" and that this did not cover an instance where the

relocation would be for the convenience of a single individual.

THE CONCERN OF THE BOARD

It is the policy of the Board to publish notice of an application for a permit to construct a transmission line for which the applicant has not acquired the right of way. The situation did not arise with regard to the subject transmission line as, when Permit and Licence No. AP 72-2 was issued, Alberta Power had already obtained permission to construct the transmission line from the Alberta Power Commission and the document issued by the Board merely formalized the earlier decision of the Commission as is contemplated by the provisions of The Hydro and Electric Energy Act. Alberta Power argued that a public interest referred to in section 13 would be a purpose of the Act as set out in section 2. The Board agrees that the purposes set out in section 2 would be matters of public interest, but does not agree that the phrase "public interest" in section 13 can be given that narrow an interpretation. If it were intended that section 13 be so interpreted, it could have referred to the purposes in section 2 rather than to the public interest.

An application for a direction under section 13 was a suitable, and perhaps the only, way for the applicants to bring their complaint before the Board. It was suitable because such a direction would effectively provide for the possible change the applicants were seeking. An application for direction under section 13 is not an application for a hearing in accordance with section 41 of The Energy Resources Conservation Act and is not affected by the time limitation in section 41. If section 13 is to have the full use that the Board believes it was intended to have, then the direction under that section may be made at any time during the life of the transmission line.

The Board believes that before a transmission line is constructed each landowner affected should have the opportunity of expressing his views to the Board. In most cases the landowner grants an easement to the person proposing the transmission line and it is taken that he has decided to forego this opportunity. The Board believes this is a matter of public interest, but it is not the public interest referred to in section 13. To come within section 13 it must be in the public interest to actually alter or relocate the transmission line.

THE EFFECT OF THE TRANSMISSION LINE ON THE PUBLIC INTEREST

To evaluate the transmission line in the light of the public interest, it is ncessary, as is often the case, to consider a number of public interests affected by the transmission line and to weigh the pros and cons to reach a net public interest effect.

The economic, orderly and efficient transmission of electric energy to consumers within the Province is the overriding public interest affected by the subject transmission line. It was not disputed that this transmission line is necessary and desirable for the transmission of electric energy from Grande Cache to Grande Prairie. However, as between the route now established for the transmission line and the alternative routes, there would appear to be little reason to choose one or the other on the basis of this public interest.

It is a matter of public interest to have transmission lines so located as to be compatible with the best present and future uses of land in the area. There were conflicting views expressed at the hearing regarding this matter. The Board believes that the basic issues raised by the applicant and intervener relate to whether the subject transmission line is suitably located, having regard to the public interest,

(a) in its general route north of the Wapiti River having regard for the existing 25 KV transmission line, and

(b) in the immediate area of the South-west quarter.

THE GENERAL ROUTE OF THE SUBJECT TRANSMISSION LINE NORTH OF THE WAPITI RIVER

ERCB Report 71-C-HE[1], Table 1, Part A, includes data which shows that increased transmission capability of approximately 70 to 100 megawatts (MW) is required in 1972 to carry energy north from the Milner Plant at Grande Cache. To obtain this capability with 25 kilovolt (V) transmission lines is

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(1) In the Matter of an Application of Canadian Utilities, Limited for Approval of the Construction and Operation of an Addition to the Battle River Power Plant, and for an Order for its interconnection. October 1971.

impracticable because 20 lines side by side might be required and a line of the type proposed and operating at 144 KV or 240 KV is the sensible alternative.

The route of the new 144 KV transmission line north of the Wapiti River is approximately one-half mile east of the existing 25 KV Gold Creek line as shown on Appendix I to this decision. The Crystal Lake substation located in the North-east quarter of Section 30, Township 71, Range 5, West of the 6th Meridian supplies energy to the 25 KV Gold Creek line, which is located south of the substation through the centres of Sections 30 and 9 and then east half a mile to continue south between Sections 17 and 18, and passing through the west side of the Pine Valley subdivision, across the Wapiti River and eventually to the Gold Creek gas plant.

(1) Views of the Applicants

The applicants, Mr. and Mrs. David Thiessen, referred to the existing 25 KV Gold Creek line as an existing heavy duty transmission line and stated that south of the Wapiti River the existing line and the proposed line were on the same right of way and that north of the Wapiti River the proposed line should have been located on the same right of way as the existing 25 KV line. One of the applicants' witnesses, Mr. Thompson, the operator of a trailer park on the North-east quarter of section 19, expressed concern for the safety of children at the trailer park who might fly kites and also some concern about television reception after the transmission line was in operation. Mr. Thompson did not express an opinion as to where the transmission line should be relocated, only that it should not be on the approved route.

Another witness for the applicant, Mr. Neufeld, referred to the wilderness nature of land near the Wapiti River which was crossed by the right of way of the proposed transmission line, and expressed the opinion that the proposed line should have been placed on the same right of way with the existing 25 KV Gold Creek line. This witness stated that he was a co-ordinator of Physical Education at the Composite High School in Grande Prairie and a director of Camp Wapiti. While not an expert on the subject of biology, as a concerned citizen his position was that existing transmission lines and rights of way should be used in preference to establishing new rights of way.

(2) Views of the Intervener

The intervener, Alberta Power, stated that the proposed high voltage line was not located beside the existing 25 KV

Gold Creek line because it would have necessitated obtaining 60 feet of extra right of way adjacent to the existing right of way. Had this alternative been adopted the line would be located closer to the City of Grande Prairie, and would result in a greater interference to a greater number of people because of existing subdivisions and future subdivision developments adjacent to the city. The intervener stated that placing the approved line beside the existing 25 KV Gold Creek line would also have resulted in forcing a line of this magnitude through the existing Pine Valley subdivision. Alberta Power further stated that south of the Wapiti River a much larger right of way was required to allow for the existing 25 KV line, the proposed high-voltage line and a future second high-voltage line, but north of the Wapiti River the two high voltage lines would be combined on the proposed 60-foot wide right of way.

Alberta Power contended that the approved line was of a type which would accommodate a second high power line on the same structures and thereby obviated the necessity of acquiring additional right of way over the private lands when a second circuit is required.

Alberta Power stated that a route beside the Alberta Resources railroad was also considered. Land costs were not determined because it was rejected on engineering considerations such as the number of bends in the route, and also on considerations of the proximity to current developments and future subdivisions and the effects on private lands and dwellings.

The intervener's submission listed the approvals that it had received from various authorities including the Permit and Licence No. AP 72-2 of the Energy Resources Conservation Board.

The intervener's comments on the safety aspects of the line are set out later in this decision.

(3) Views of the Board

The Board accepts that additional transmission capacity at 144 KV or higher voltage is required and, purely from a technical viewpoint, the proposed construction is suitable. The Board agrees that the use of structures which will allow a future second high-voltage line to be suspended from the same poles, and the use of one high-voltage corridor is good planning, which helps to reduce the number of lines crossing the countryside. The Board also believes that it is good planning to locate any high-voltage line, which happens to parallel the City boundary as far from the City as practicable.

The low-voltage 25 KV lines used to distribute electric energy to local customers require minimum rights of way, and are located along roadways and lanes and are extended, moved and changed as the load requirements may dictate. Although an existing high-voltage right of way may be a good location for a proposed lower-voltage line, in the Board's view there is little advantage in locating the larger and more conspicuous high-voltage lines on new right of way beside the existing right of way of lower-voltage lines. On the other hand it does appear advantageous to locate more than one high voltage transmission line on the one right of way rather than developing separate right of way. Thus, from an overall planning point of view the Board believes that the Alberta Power route north of the Wapiti River is reasonable. Nevertheless the Board has considered the costs associated with relocating the proposed line beside the existing 25 KV line from the Wapiti River to the Crystal Lake substation. The minimum extra cost of lost construction would be approximately $24,000.00 (8 miles at $3,000.00 per mile as stated by Alberta Power), plus lost easement payments plus the payment to property owners on the new route. Such a cost could probably not be borne by the applicants or if borne by Alberta Power would not be in the interest of consumers of electricity in the Grande Prairie and adjacent northern areas.

The Board concludes that, from the point of view of providing the necessary transmission of electric energy, that the route of the subject high-voltage transmission line, with provision for a second high voltage line on the same structures, is satisfactory and that this public interest would not require the relocation of the line to the route of the existing 25 KV Gold Creek transmission line.

THE ROUTE OF THE TRANSMISSION LINE IN THE AREA OF THE SOUTH WEST QUARTER

(1) Views of the Applicant

The applicant, Mr. Thiessen, stated that he already had two power lines on his property, one, the rural electrification line serving his buildings, and the other one pole and two guy wires of the 25 KV Gold Creek line. The applicants have cultivated approximately 115 acres of the South-west quarter and approximately 100 acres of this cultivated land is north of the house, and would be traversed east to west by the proposed high-voltage transmission line route. The applicants did not enlarge on the impact of the proposed high-voltage line on the farming operations on their cultivated lands, but did state that their position was that they did not want the line on the

property and were concerned about the safety aspect of the lines crossing the property.

The applicants stated that one proposal was to route the line on the west side of their property immediately in front of their new home and that this location was unacceptable. The applicants also stated that in the event of future subdivision of the property the transmission line would restrict the type of development and they would thereby lose land and money.

Mr. Thiessen stated that although he had not raised the question of the possible effect of the high voltage line on the trumpeter swans prior to the Board of Arbitration hearing, he had seen a number of swans using the lake during the Fall of 1971, and had seen approximately 25 to 30 swans using the lake during the Spring of 1972, but to the time of the hearing, not nesting The applicants stated that the line would present certain hazards to the water fowl in the area but did not describe such hazards in detail. Mr. Thiessen referred to the brief submitted to the Board by the Canadian Wildlife Service, Federal Branch of Lands and Forests and Wildlife.

The applicants' witness, Mr. Newfeld, read a statement from the Wapiti Fish and Game Association which agreed with the above mentioned brief and deplored the minimum protection afforded trumpeter swans nesting areas by the draining of lakes, damming of lakes and construction of power lines.

(2) Views of Alberta Power

The intervener, Alberta Power, noted that the applicants had applied for an order of the Energy Resources Conservation Board directing relocation of a portion of the proposed transmission line but had not indicated the portion of the transmission line sought to be relocated nor the location to which it should be relocated. The intervener stated that an easement had been obtained from the Department of Lands and Forests and from all private owners other than the applicants and one other owner.

Alberta Power stated that prolonged negotiations took place between it and the applicants,extending from July, 1971 to February 22, 1972. The first proposal made by Alberta Power was for the line to run along the west boundary of the applicants' land, but this route was discarded when the applicants objected on the grounds of the proximity to their dwelling. Another alternative involved locating the high voltage line along the east and north sides of the applicants' quarter section. This alternative would have required the relocation of an air strip on the adjacent Johnson Farms at an estimated cost of

$5,000 to $10,000, which Alberta Power was prepared to underwrite. This route was not feasible, however, when the applicants refused to grant an easement along the eastern and northern boundaries of their property. The interveners stated that another alternative was to have the line by-pass Wood Lake and run diagonally across the Gable farm to the mid-point of the applicants' southern boundary, thereafter continuing north to the northern boundary of the quarter section. This alternative was also not acceptable to the applicants. In view of the lack of success in obtaining agreement from the applicants on any of the proposed alternatives, Alberta Power stated that it proceeded to select the current route and obtain the necessary easements.

With respect to the question of the safety of the various lines, the intervener stated that safety has no direct relationship to the voltage of the line and that it can be just as lethal to fly a kite into a 5 KV line as into a 240 KV line. With respect to the physical strength which prevents a line falling to the ground, Alberta Power stated that the high-voltage transmission lines incorporate greater safety factors than the lower voltage 25 KV or rural lines. Such differences in strength safety factors affect the reliability of service of the lines. For the safety standards affecting people, construction must comply with the standards under The Electrical Protection Act of Alberta, and the intervener stated that the proposed high-voltage line would comply with such standards.

In connection with the effects of the line upon the environment and specifically with regard to the use of Wood Lake by trumpeter swans, the intervener stated that the Provincial Department of Lands and Forests had granted a letter of authority covering construction of the line through Crown Lands. Alberta Power expressed an opinion that the transmission structures and conductors were of such a size as to be entirely visible to the birds and were no more of an obstacle to flight than natural objects such as trees. The applicant further stated that the Alberta Power staff in the Grande Prairie area, responsible for the maintenance and operation of transmission lines, have not reported any cases of swans coming in contact with the transmission lines even though another nesting ground, Clairmont Lake, is almost surrounded by transmission lines.

(3) Views of the Board

Prior to the hearing the Board staff communicated with the Department of Lands and Forests with respect to trumpeter swans and were referred to the Canadian Wildlife Service, Federal Branch of Lands, Forests and Wildlife. Mr. A. H. McPherson, Regional Director, submitted a brief to the Board, with a copy to the applicant. The Board later provided a copy to the

intervener, Alberta Power. This brief stated that the swans now numbered about 5,000 in North America, 125 of which originated in Canada, with about 100 of this 125 being from the Grande Prairie area. About two years ago this bird was removed from the endangered species list when the population increased to a safe level, but the brief notes that the Grande Prairie area can at present support no more than thirty-five nesting pairs. The brief also states that trumpeter swans fly quite low when congregating prior to migration in the Fall and that there are numerous records of casualties caused by the large birds flying into power lines. The brief does not state whether or not such casualties have occurred in the Grande Prairie area but it does recommend that power lines be built as far as possible from nesting grounds and at least one-half mile from the shores of Wood Lake. Mr. McPherson did not attend the hearing but the Board has accepted the brief as providing useful and relevant information.

The Board has considered the various alternative routes available to Alberta Power for a transmission line in or adjacent to the south-west quarter. With respect to the route that would lead to the transmission line being located close to the Thiessen residence, the Board appreciates the view of the applicant and agrees that this alternative is not satisfactory.

The feasibility of an alternative route, which would result in the transmission line being located on the western and northern perimeters of the South-west quarter, was dependent upon the relocation of the Johnson Farm Limited air strip. Inasmuch as the applicant and another adjacent landowner would not grant easements to Alberta Power, which would have permitted the relocation of the air strip, this potential route is no longer a viable alternative. The Board has therefore not given this possibility further consideration.

A third alternative route would have the transmission line by-passing the South-western edge of Wood Lake, running diagonally through Section 17 to the midpoint of the southern border of the South-west quarter, running due north to the northern boundary and then west. This route appears to have the same effect on the applicant's land and farming operations as the approved route. It does, however, have a negative effect on the farming operations of Mr. Gable. The resultant line would be located up to a quarter of a mile away from the western shores of Wood Lake. The Board notes that the Wild Life Service contended that the flight path of the trumpeter swans is habitually low prior to migration in the Fall and that to be beneficial the transmission line should be located at least one-half a mile from the shore of the lake. In

view of these comments it may be that the location of the transmission line a short distance from the lake might actually increase the hazards for the trumpeter swans rather than improve them. It therefore appears to the Board that this alternative does not offer any advantages over the current route and in fact has some disadvantages.

Having regard to the alternatives available for the routing of this transmission line in the immediate area of the South-west quarter, the Board concludes that the existing route offers less disadvantages than any other alternative. In presenting evidence as to the priority of his objections to the construction of the high-voltage line across his property, Mr. Thiessen indicated that to him the trumpeter swans were more significant than the effect of the line on his farming operations, and the Board concludes that the effect on such farming would be offset by the compensation to be awarded by the Board of Arbitration.

The Board recognizes that the route may not be favourable to trumpeter swans using Wood Lake. However, as stated previously, the Provincial Department of Lands and Forests has granted a letter of authority covering construction through the main portion of the lake traversed by the line. The Wildlife Service stated that swans have nested only seven out of the last thirteen years on Wood Lake and that the lake would appear to be smaller than the normal nesting area for a pair of swans. Furthermore, it appears to the Board that if Grande Prairie continues to develop to the east as suggested by both the applicants and the intervener, the encroachment of urban development will eventually have a negative impact on Wood Lake as a nesting ground for trumpeter swans. No evidence was submitted at the hearing to indicate that any harm or fatality had occurred to swans in the Grande Prairie area, including Clairmont Lake, which is virtually surrounded by transmission lines. On the basis of the evidence, the Board concludes that any unfavourable impact on the trumpeter swans in Wood Lake due to the transmission line traversing the South-west corner of the lake would be limited.

The Board has not been presented with any evidence that this particular high-voltage line will be unsafe and sees no reason to question the adequacy of the safety regulations established under The Electrical Protection Act.

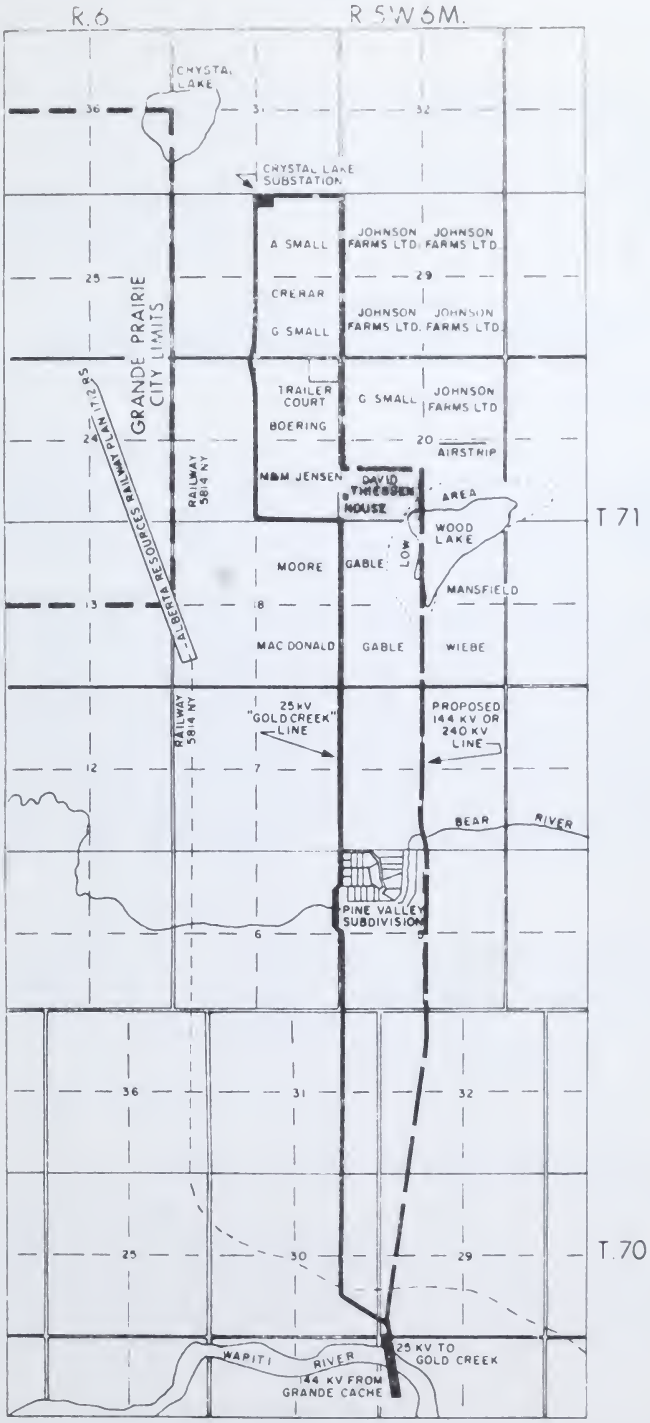
DECISION

Having regard to all of the evidence, the Board does not believe it would be in the public interest to order the relocation of the high-voltage transmission line and the Board therefore dismisses the application.

ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard
Vice Chairman

DATED at Calgary, Alberta
June 5, 1972.



APPENDIX 1 TO DECISION NO. 72-6

ENERGY RESOURCES CONSERVATION BOARD
CALGARY, ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

Decision 72-7
Application No. 6150

GAS PROCESSING
WHITECOURT FIELD AND BLUERIDGE FIELD

THE APPLICATION AND HEARING

Pacific Petroleums Ltd. applied under section 38, clause (b) of The Oil and Gas Conservation Act for amendment of an approval which would authorize an increase in the gas throughput of the Whitecourt Gas Processing Plant, located in Legal Subdivision 12, Section 26, Township 59, Range 11, West of the 5th Meridian. The maximum raw gas inlet rate would increase from 50 million cubic feet per day to 65 million cubic feet per day which would result in the production of 61.4 million cubic feet per day of sales gas and 452 barrels per day of stabilized pentanes plus. Acid gas removed from the raw gas would be flared at the existing 300-foot flare stack which would result in a maximum sulphur dioxide emission rate of 14.7 long tons per day. The present Whitecourt plant is authorized by Approval No. 1463 which currently permits the emission to the atmosphere of 11.3 long tons per day of sulphur dioxide.

Submissions in opposition to the application were filed by Mr. Alex Watson, Mr. F. A. Watson, Mr. E. Juengling and the Blue Ridge Rural Development Association. The application was heard at the Provincial Building Court Room in Mayerthorpe, Alberta, on April 13, 1972, by the Board with D. R. Craig, P. Eng., and V. Millard sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Pacific Petroleums Ltd.	A. A. Phillips	Pacific
Alex Watson	Alex Watson	
F. A. Watson	F. A. Watson	
E. Juengling	E. Juengling	

	Represented by	Abbreviation Used in Report
Blue Ridge Rural Development Association	R. Pritchard	Association
Board Staff	R. B. Dunbar, P.Eng.	

Witnesses for Pacific were G. C. Whittaker, P.Eng., and D. R. Broughton, P. Eng.

SUBMISSION OF APPLICANT

Pacific applied for the increase in plant throughput to meet sales gas contract commitments. No basic change in plant equipment would be required to process the additional gas.

The acid gas, containing 9.4 per cent hydrogen sulphide and 90.6 per cent carbon dioxide, would be flared through the existing 300-foot flare stack at a maximum rate of 2.0 million cubic feet per day. Pacific stated it would add a minimum of 0.54 million cubic feet per day of fuel gas, consisting of 0.42 million cubic feet per day of residue gas and 0.12 million cubic feet per day of stabilizer overhead and flash tank vapours, to the acid gas prior to flaring, at the maximum sulphur dioxide emission rate, to ensure complete combustion of the acid gas and dispersion of the gases leaving the flare. There would be no other source of pollutant emission from the plant during normal operations.

Pacific stated that it had evaluated the possibility of recovering sulphur at the plant to reduce or eliminate sulphur dioxide emissions. It estimated the cost of Claus sulphur recovery facilities to be approximately $400,000. Net operating income was estimated to be a maximum of $6,900 per year so that approximately 58 years would be required to pay out the facility. Pacific submitted that, in addition to the poor economics, sulphur recovery using the Claus process would be technically difficult due to the low hydrogen sulphide content of the acid gas, which is 9.4 per cent hydrogen sulphide. Pacific concluded that sulphur recovery using the Claus process would not be practical due to the high cost involved and technical difficulties associated with processing acid gas of low hydrogen sulphide concentration, and because recovery would not be complete and some sulphur dioxide emission would still occur.

Pacific reported that it did not consider sulphur recovery processes other than the Claus process due to their higher capital and operating costs. Also it had studied the feasibility of injecting the acid gas to an underground formation.

This scheme was estimated to cost some $800,000. The operating costs would be approximately $100,000 per year. Pacific concluded that this method of acid gas disposal would also not be practical due to the high costs and metallurgical and safety problems that might be experienced with such a facility.

Pacific submitted that, in view of the disadvantages of the alternative methods of acid gas disposal studied, the proposed flaring would be the only practical method of disposing of the acid gas.

Pacific submitted the results of calculations that indicate a maximum calculated sulphur dioxide concentration of 0.20 parts per million at ground level at the maximum proposed emission rate. This concentration would not exceed the applicable Provincial standard of 0.20 parts per million maximum calculated concentration at ground level. The maximum calculated concentrations at the residences of A. Watson and E. Juengling, both interveners at the hearing who live close to the plant, would be approximately 0.15 parts per million.

Pacific stated that it had carried out extensive air quality monitoring in the vicinity of the plant to determine actual atmospheric sulphur dioxide and hydrogen sulphide concentrations. During 1972 an air quality monitoring trailer was located on the Juengling farm, 4 miles south-east of the plant, during the period February 1 to March 1 and on the farm of A. Watson, 3½ miles south-east of the plant, during the period March 3 to April 3. The maximum hourly average concentrations detected by continuous measurement at the Juengling and Watson farms during these two surveys were 0.139 and 0.079 parts per million respectively. Concentrations exceeding a one-half hour average of 0.20 parts per million were not detected. North-west winds that would carry gas from the plant towards the monitor occurred 17.2 per cent of the time during the Juengling survey and 37.9 per cent of the time during the Watson survey.

Pacific reported that its exposure cylinder monitoring program has indicated acceptable total sulphation and hydrogen sulphide exposures. Total sulphation levels measured monthly at each of eight stations have been below the acceptable level, as defined by the Department of the Environment, of 0.3 milligrams of equivalent SO_3 per day per 100 square centimeters and hydrogen sulphide levels have been below the acceptable level of 0.1 milligrams of equivalent SO_3 per day per 100 square centimeters.

Pacific concluded that because both measured and calculated concentrations were within Provincial standards the proposed flaring of acid gas should not have adverse environmental effects.

SUBMISSION OF ALEX WATSON

Mr. Alex Watson objected to the granting of the application claiming that:

1. Sulphur dioxide and sulphuric acid present in the atmosphere due to emissions from the plant are harmful to his well being, especially since he has been classified as a respiratory cripple by his doctor due to bronchitis and emphysema.

2. When there is a north-west wind there are times when his cattle cough and their eyes water which he stated might be caused by sulphur dioxide emissions from the Pacific plant.

3. Rusting of his fences and machinery has accelerated since the plant went on stream.

4. Emissions from the plant might be directed to his farm during north-west winds due to its relatively high elevation and the influence of terrain on wind flow in the area.

SUBMISSION OF F. A. WATSON

Mr. F. A. Watson opposed the application and a further increase in sulphur dioxide emissions to the atmosphere. He stated that in his opinion:

1. The air in the area is already polluted to the critical level with the amounts of sulphur dioxide now being exhausted to the atmosphere.

2. His small daughter's health is being affected by sulphur dioxide now in the air and increased emissions will only worsen the condition now existing.

3. Barbed wire is corroded by sulphur dioxide in the air.

4. The health of his cattle is affected by sulphur dioxide emissions from the plant.

Mr. Watson stated that he believes a thorough investigation of problems now experienced in the area is required before any further increase in sulphur dioxide emission rates be permitted.

SUBMISSION OF E. JUENGLING

Mr. E. Juengling expressed opposition to the application stating that sulphur dioxide emissions from the plant are harmful to the health of his family and his cattle.

SUBMISSION OF THE ASSOCIATION

The Association expressed opposition to permitting a further increase in sulphur dioxide emissions from the plant because of foul odours now in the area and a possible health hazard to people, animals and plants. The Association stated that because much of the land in the plant vicinity is higher in elevation than the top of the stack this land could be exposed to the high sulphur dioxide concentrations in the plume. It stated that farmers in the area have observed excessive rusting of machinery, wire fences and antenna guy wires which might be caused by sulphur dioxide emissions from the stack. Yellow dust, which could be sulphur, was often found on flat roofs in the spring. The Association speculated that heavy hail storms experienced in the last few years could have been caused by sulphur dioxide in the air which originates from local gas processing plants.

VIEWS OF THE BOARD

Board staff calculations of ground level sulphur dioxide concentrations have been carried out and confirm those of the applicant that the calculated maximum concentration does not exceed the 0.20 parts per million standard. The Board recognizes that under some atmospheric conditions, short duration concentrations could exceed the calculated maximum. The Board also recognizes that terrain will influence plume behaviour and could retard dispersion of pollutants under some conditions. Monitoring by both Pacific and the Department of the Environment, however, has not detected any concentrations exceeding the Provincial standards or any sufficiently high concentrations to adversely affect the health of humans, other animals or plants.

While the monitoring carried out by Pacific and the Department of the Environment indicates that sulphur dioxide concentrations exceeding the Provincial standards have not been detected in the past, the Board has concluded that, in view of the complaints it has received, there should be

further effort to confirm the validity of such observations by additional monitoring. The Board will require that Pacific carry out a program of continuous monitoring for not less than six months during the next year to further evaluate sulphur dioxide concentrations in the area. The Board will also ask the Department of the Environmment to conduct a survey in the area for at least a one-month period at a location on the farm of Mr. Alex Watson. The Board will ask Pacific and the Department to advise the interveners of the results of the surveys and will also report its views to the interveners after studying the results. The requirements of the approval will be reviewed upon completion of the additional testing program.

The Board recognizes that corrosion of metals can be accelerated by the presence of sulphur dioxide in the air. However, since the air quality monitoring conducted to date has not indicated unacceptable sulphur dioxide concentrations, the Board is of the opinion that the resultant corrosion would be minor. The Board will remain cognizant of this potential problem in consideration of the results of the required additional testing.

The Board has considered the evidence of Pacific concerning alternative means of disposing of the acid gas and has concluded that it would be neither technically nor economically reasonable to require the recovery of sulphur at the Whitecourt plant. Injection of the acid gas to an underground formation is also not practical in this case in the opinion of the Board. It believes that the proposed disposal of the acid gas from the existing flare stack is acceptable since all normal pollution abatement requirements have been met, past monitoring has not indicated unacceptable concentrations and the allegations of the interveners that human, animal and plant health problems and materials corrosion have been caused by sulphur dioxide emissions from the plant have not been substantiated.

DECISION

The Board will grant the application by Pacific for an increase in the gas throughput of the Whitecourt gas processing plant and an increase in the sulphur dioxide emission rate to a maximum of 14.7 long tons per day. The Board will require that Pacific conduct an extensive satisfactory monitoring program over a one-year period after which the

approval will be reviewed and amended if necessary. The amendment of Approval No. 1463 is being issued concurrently with this decision.

ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard
Vice Chairman

DATED at Calgary, Alberta
June 2, 1972

ENERGY RESOURCES CONSERVATION BOARD

Decision 72-8
Application No. 6188

EXEMPTION FROM SULPHUR RECOVERY GUIDELINES HARMATTAN LEDUC GAS PROCESSING PLANT

THE APPLICATION AND HEARING

Canadian Superior Oil Ltd. applied pursuant to The Oil and Gas Conservation Act for exemption of the Harmattan Leduc Gas Processing Plant from the sulphur recovery efficiency guidelines outlined in the Board's Informational Letter No. 71-29. The plant at present has approval to process up to 506 long tons of sulphur per day and is required to recover a minimum of 95 per cent of the sulphur in the inlet gas. The guidelines state that a plant processing a favourable quality acid gas containing from 400 to 1000 long tons of sulphur per day should be required to recover from 96 to 98 per cent of the sulphur in the inlet gas.

The following people wrote or signed submissions of intervention: Mr. and Mrs. Lloyd Chandler; Mr. and Mrs. David Morgan, Mr. and Mrs. Warren Conrad, Mr. and Mrs. Grant Moore, Mrs. R. M. Turnbull, Mrs. Margaret Watson, and Mr. and Mrs. J. Conrad; Mr. Don McCracken and Mr. and Mrs. Richard Ross; Mr. Don Morgan, Mr. Garnet Funkhouser, Mr. and Mrs. William Wiper, Edith Wiper, Mr. Jim Conroy, Mr. and Mrs. A. W. Johnson, Mr. and Mrs. W. H. Caush, Mr. and Mrs. George Fagan, D. C. MacKinnan, Mr. Doug Hosegood, Mrs. Wilfred Befus, Mrs. Brooks E. Brinson, Mrs. Irene Nimmons, Mr. Stan R. Bell, Mr. Fred Notley, W. R. Hildebrandt, Mr. Wilfred Blain, Mrs. Caush, B. Brinson, and H. J. Sawatzky; Mr. and Mrs. Archie Stockburger; Mr. and Mrs. M. A. Knights; Mr. and Mrs. R. H. Ross, Mrs. Junette McCoy, M. McEwen, and W. E. Reinhardt; Mr. and Mrs. Howard Christensen; V. Eggins, Mr. William Wigley; Mrs. Margarite Albanese; and Mrs. Irene Nimmons. These interveners are residents in the general area of the plant. An intervention was also received from the County of Mountain View No. 17 in which the plant is located.

The hearing of the application commenced at the offices of the Board in Calgary on March 29, 1972 with examiners G. J. DeSorcy, P. Eng., R. L. Harrop and N. A. Strom, P. Eng. sitting. The hearing was adjourned and subsequently continued at Olds, Alberta on April 26, 1972.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Canadian Superior Oil Ltd.	R. C. Macdonald B. D. Garrison A. Shklanka B. Marjanovich G. A. Jelinski D. J. Parkhill J. B. Doyle	Canadian Superior
Mrs. Lloyd Chandler		
Mrs. Howard Christensen		
Mrs. Braun		
Mrs. David Morgan		
Mr. Archie Stockburger		
Mrs. R. H. Ross		
Mr. William Wigley		
Mr. Hosegood		
Mrs. Margarite Albanese		
Mr. Chandler		
Mr. Brooks E. Brinson		
Country of Mountain View No. 17	C. W. Lockwood Dr. Sutmoller W. N. Bagnall M. Hanna W. Synder	County
Board Staff	L. A. Mazurek, P. Eng. P. A. Joziasse	Staff

Mr. Lockwood also represented a number of the interveners. The witnesses who appeared on behalf of the County were Dr. Sutmoller, a veterinarian, Mr. W. J. Bagnall, Reeve of the County, Mr. Max Hanna, a farmer in the County, and Mr. Walter Synder, Agricultural Fieldman for the County.

BACKGROUND

The Harmattan area is underlain by two principal hydrocarbon-bearing zones, the Elkton Shunda formation and the Leduc formation. Raw gas from the Elkton formation, some of which is produced along with crude oil, is slightly sour and is processed primarily in what is known as the Harmattan Area Plant. A small quantity of acid gas from this plant is transmitted for further processing to the sulphur recovery facilities at the Harmattan Leduc Plant. Gas from the Leduc formation is not associated with oil, is extremely sour and is processed entirely in the Harmattan Leduc Plant. These two plants are located on the same site and both are operated by Canadian Superior, thus giving the impression that there is only one plant on the site. The two plants operate essentially independently of each other and do not have common ownership.

The Board's present approval for the Harmattan Leduc Plant requires a minimum sulphur recovery efficiency of 95 per cent and permits the emission of a maximum of 25.3 long tons per day of sulphur to the atmosphere. The sulphur is exhausted in the form of sulphur dioxide from an incinerator stack 250 feet in height.

The Elkton Pool and the Harmattan Area Plant

The Elkton Pool was discovered in 1954. A total of 76 oil wells and 13 gas wells have been completed in the pool since its discovery. Gas production exceeds one hundred million cubic feet per day and the gas contains from approximately 0.4 to 0.6 per cent hydrogen sulphide. Until April 1972, the oil was produced to 14 separate batteries with some associated gas being flared at each battery. In April 1972, a field-gate system was put into operation so that all the oil is now produced to one location. When the field-gate system is fully operational there should be no flaring of Elkton gas in the field.

In 1960, the Board approved a gas cycling scheme to produce raw gas, recover hydrocarbon liquids and inject lean gas back into the Elkton Pool. It was for this purpose that the Harmattan Area Plant was built. Hydrogen sulphide from approximately four per cent of the raw gas feed is removed at the Area Plant. This percentage will increase in the near future with the partial sale of gas from the plant. The remainder of the raw gas, after removal of liquid hydrocarbons, is reinjected into the Elkton reservoir. On occasion, when operating difficulties occur at the Harmattan Area Plant, gas containing small amounts of hydrocarbon liquids is flared. This has resulted in the occasional emission of black smoke at the plant.

The Leduc Pool and the Harmattan Leduc Plant

The Leduc Pool was discovered in the early 1960's and much development and testing took place in 1964. The Harmattan Leduc Plant was constructed and put on stream in 1966 under Board Approval No. 1454. There are eight Leduc wells, five of which are presently producing to the plant. Gas production amounts to approximately 22 million cubic feet per day and

the gas contains about 53 per cent hydrogen sulphide. Due to the exceptionally high hydrogen sulphide content of the Leduc gas, the producing wells have a serious problem of sulphur deposition in the tubing and consequently the wells have to be washed every two or three months with carbon disulphide and condensate. When these wells are put back on stream, the wash fluids are generally sent to the plant through the flow line. On occasion, the fluids have been disposed of by flaring at the well site. When this has been done there has usually been an emission of black smoke for a few minutes. The procedure for testing Leduc gas wells generally involves flaring of the produced gas at the well site. This results in the release of substantial volumes of sulphur dioxide to the atmosphere through a flare stack of approved height.

Complaints of odours, smoke and livestock illness were first received from the residents of the Harmattan Area in 1964. In 1966, after the Harmattan Leduc Plant went on stream, many more complaints were received relating to odours, smoke, effect on livestock and corrosion of fence wire and equipment. Many of the complaints implied or suggested that the "Harmattan Plant", actually the two separate plants, was to blame for the problems.

Since 1971 with the Board's greater concern for pollution and increased surveillance by the Board staff, many significant changes to operations have been made with consequent reduction of the impact on the environment. These changes include expansion of the inlet separation facilities at the Harmattan Area Plant, consolidation of the 14 separate Elkton batteries into a single field-gate facility, and modification to and expansion of the waste water underground disposal system. Further modifications are continuing. The frequency of complaints registered at the Board's Red Deer Field Office has declined over the past year or so reflecting the improved situation.

SUBMISSION OF THE APPLICANT

Canadian Superior submits that there is sufficient economic justification to warrant exemption from the sulphur recovery guidelines. It stated that the capital cost of a stack gas clean-up facility required to raise the sulphur recovery efficiency of the plant to satisfy the guidelines would make operation of the entire plant uneconomic.

Canadian Superior pointed out that the Harmattan Leduc Plant is already operating very close to the requirements of the guidelines. Four stack surveys taken in 1971 indicated that the plant was operating at an average recovery of 95.5 per cent, just 0.5 per cent below the lower end of the guideline requirement range of 96 to 98 per cent. It also pointed out that for the months of February and March of 1972, the stack emissions have averaged below what would be the average permitted emission if a sulphur recovery efficiency of 96 per cent had been required. The applicant stated that increasing the sulphur recovery efficiency from the present level of about 95.5 per cent to 96 per cent would decrease the total emission of sulphur by only 3 long tons per day.

Estimates by the applicant place the cost of a stack gas clean-up facility, which would bring the overall sulphur recovery efficiency up to about 98 per cent, from $1.2 million to $2.0 million. These estimates were based on an IFP type process which Canadian Superior believes to be most suited for the Harmattan Leduc Plant. In reply to questions, Canadian Superior stated that it probably would not be possible to upgrade the existing facility to achieve a 96 per cent recovery level without the addition of stack gas clean-up facilities.

Canadian Superior stated that in 1972 the overall Harmattan Leduc Plant is expected to realize a net operating loss of almost $90,000. It stated that this is due primarily to depressed sulphur prices caused by a world-wide over-supply of sulphur. Canadian Superior made reference to a commitment to the Canadian Pacific Railway for shipping one and one-quarter million tons of sulphur over a specially-built rail system from Didsbury to the Harmattan Leduc Plant. This commitment covers a ten-year period ending in 1976. If the plant were shut down now, Canadian Superior, under the terms of the commitment would have to pay in excess of one-half a million dollars to the Canadian Pacific Railway for sulphur not shipped. A witness for Canadian Superior stated that it "intends to make adjustments in plant operations to try to reach a break even situation where the plant can actually pay out its railroad commitments and hope for better sulphur markets in the future".

In its submission, Canadian Superior stated that it expects that the sulphur price will increase to $20 per long ton by 1979 from its present level of $7.25 per long ton. However, in reply to questioning, a witness for Canadian Superior stated that the forecast was optimistic and that the maximum price now expected in the foreseeable future is $12 to $15 per long ton. The applicant stated that it would have no hesitation in installing stack gas clean-up facilities if it could be sure of 100 per cent sales of sulphur at the forecast prices.

According to the cost and income forecasts submitted by the applicant, the plant could be operating at a net loss of up to $200,000 annually until 1977. For this reason and due to the uncertainty of sulphur prices in the future, Canadian Superior said that it has not made an estimate of when a stack gas clean-up facility could be paid out.

Canadian Superior stated that, should its application not be granted, it would seriously consider shutting down the plant rather than install a stack gas clean-up facility. This decision, however, would be up to all of the owners of the plant of which Canadian Superior is only one.

Canadian Superior stated that it has spent in excess of $170,000 in the last two years to improve pollution control at the plant. It expressed its belief that no damage is being done to the environment by sulphur dioxide emissions from the plant. Canadian Superior contended that an aerial photography study submitted by it showed any existing stress in the vegetation in the area of the plant to be due to the season, location and time of year and not to sulphur dioxide emissions from the plant. It said that investigation showed that almost all of the complaints received at the plant could be directly related to plant upsets and that some of the complaints were related to operation of the Harmattan Area Plant.

Canadian Superior stated that it operates 11 exposure cylinder stations and one mobile monitoring trailer in the area of the plant for the purpose of measuring the concentrations of hydrogen sulphide and sulphur dioxide in the atmosphere. On a few occasions the concentrations exceeded the Provincial ground level standards, but nearly every occasion was related to a plant upset. Canadian Superior stated that it believes the monitoring program is satisfactory.

SUBMISSIONS OF THE INTERVENERS

All the interveners stated their opposition to the application of Canadian Superior for exemption from the sulphur recovery guidelines. While it appeared that certain of the interveners were under the impression that the application was for an increase in emissions, almost all stated that the plant should be made to reduce emissions.

Most of the submissions were in the form of complaints of pollution in the area. Incidents of sick cattle, dead vegetation, corroded machinery and human discomfort and distress were reported and in some cases were attributed to pollution from the Harmattan Leduc Plant.

Mr. and Mrs. B. E. Brinson, who live 5 miles east of the plant, submitted a "pollution log" which indicated a high frequency of occurrences of sulphurous odors at their farm when there was a west wind. Several interveners stated that they have seen black smoke coming from the Harmattan Plants on many occasions.

A number of interveners, most notably Mr. and Mrs. L. Chandler and Mrs. R. H. Ross, expressed their concern about the human discomfort, and in some cases, distress, brought about by sulphurous fumes in the atmosphere. According to testimony, these fumes have awakened people from sleep, have forced evacuation from dwellings, and in some cases have forced people to seek medical attention, especially those suffering from emphysema.

A number of interveners stated that their cattle and hogs were being affected adversely by emissions from the plant. Complaints of respiratory ailments, misformed feet, sterility, death, and generally poor conditions were brought forward and attributed to operation of the plant and to field operations. Dr. H. Sutmoller, a veterinarian from Didsbury testifying on behalf of the County, stated that an excess of sulphur in the soil could have serious nutritional effects on vegetation and livestock because it inhibits the intake of selenium. He stated that selenium is an essential element in the metabolism of both plants and animals, and a deficiency of it can cause muscular dystrophy, infertility and general poor condition in all species of livestock. He stated that some sulphur is required in the soil, but the total sulphur emissions from the subject plant would be enough to satisfy the sulphur requirements of 1,440 square miles annually. He stated that sulphur dioxide was one of the minor causes of respiratory ailments in livestock in the Harmattan Area.

Several interveners stated that since the plant first went on production, corrosion in the area surrounding the plant increased dramatically. Samples of barbed fence wire, copper wire, paint chips, farming tools and a photograph of farm machinery were submitted as evidence of the corrosive quality of the atmosphere in the area around the plant. Although none of the interveners could definitely place the blame on sulphur dioxide, many stated that before the plant went on stream, corrosion did not occur nearly as quickly and severely as after the plant went on stream.

The County stated that since the plant went on stream, it has received many complaints from the area residents concerning damage to vegetation. Both crops and indigenous plants and trees have died and are dying, with the suspected cause being emissions from the plant. Mr. W. J. Bagnall stated that the County's main concern was the total amount of sulphur which goes up the stack and ultimately falls back on the land. He stated that County's first concern was the well-being and health of the residents of the County. He stated that the maximum allowable sulphur emission rate as determined by the Board should not be exceeded.

Mr. A. Stockburger stated that the damage to crops and farm equipment constituted an increase in the financial burden of the farmers, and some were finding it difficult to justify staying in the area.

Some of the interveners stated that the monitoring program around the plant was inadequate. It was suggested that more stations should be provided, both around the plant and further from the plant, instead of just at those locations which were calculated to be likely spots of high sulphur dioxide concentration.

Certain interveners, notably Mrs. Albanese, pointed out that while emissions in general may meet health and Provincial standards, little concern has apparently been shown for the long-term cumulative effects of those emissions. She stated that while the emissions may be tolerable today, it is not known what effect they would have in the future.

At least two interveners expressed concern that a decision by the Board to grant the application from Canadian Superior would set a precedent for other applications, and that other plants might expect the same consideration when applying for exemption from the guidelines.

FINDINGS

Several applications for exemption from the sulphur recovery guidelines have been denied or deferred until additional data is available respecting the performance of the relevant processing facilities. This is the first application to be analysed in detail. As such it involves a determination of how the guidelines should be applied and how applications for exemption should be dealt with. For this reason, the examiners reported their findings to the Board in a preliminary report. The Board then determined how applications for exemption from the guidelines should be dealt with and co-operated with the examiners in the final decision respecting the subject application. The remainder of this report is thus written as a joint Board and Examiners Decision Report.

On the subject of an overall policy respecting applications for exemption from the sulphur recovery guidelines, the Board believes such applications should be considered on the basis of both economic conservation and the impact on the environment of the emission to the atmosphere of sulphur not recovered. Having regard for the objective of reducing total emissions to the atmosphere, the Board's assessment of the economics of increased sulphur recovery will not be on an incremental basis but rather will normally deal with the total sulphur recovery operation. In cases where, because of the plant location relative to communities or farmsteads or because several plants are located near each other, the environmental aspects of a situation are more important, the Board may look at the overall economics of an entire operation including costs and revenue related to the recovery and sale of residue gas and liquids prior to ruling of an application.

The subject hearing was called specifically to consider the application of Canadian Superior for exemption of the Harmattan Leduc Gas Processing Plant from the sulphur recovery guidelines. At the hearing, much evidence relating to the state of the environment in the area was placed before the examiners. This evidence was generally in the form of complaints from residents. Further investigation suggests that many of the pollution complaints appear not to relate to the operations of the Harmattan Leduc Plant, but to field operations or to the operation of other processing facilities in the area. As such, these matters are not an actual part of the application for exemption from sulphur recovery guidelines. Notwithstanding this, and because of overall emission and pollution considerations they bear a relation in a general way to the subject application and in any case are of importance to the Board. Accordingly, the question of the pollution complaints in the area, the causes of the complaints and the necessary action to overcome any remaining problems will be considered in this report in addition to the matters more directly related to the subject application.

Respecting the Harmattan Leduc Processing Plant and the specific application by Canadian Superior for exemption from the sulphur recovery guidelines, the Board finds as follows:

1. Having regard for the capacity of the Harmattan Leduc Gas Processing Plant and the quality of feed gas going to the plant, the minimum sulphur recovery efficiency according to the guidelines should be 96 per cent.

2. With the current world over-supply of sulphur whereby only some 50 per cent of the 1972 sulphur production from the Province is expected to be sold at a plant price of about $7.00 per long ton, there is no economic basis by which the expenditures necessary to increase the sulphur recovery of the subject plant can be justified. In fact, the current operating expenditures are very close to the total revenue that can be expected from the plant under present circumstances. This suggests that, were it not for the existing commitment to the railway, the facilities might not continue in operation.

3. The revenue from sulphur sales plays an exceptionally important role in the overall economics of the operation of the subject plant. This is the case primarily because of the exceptionally high hydrogen sulphur content of the raw gas and the resulting small amount of residue gas per unit of gas processed, and because the residue gas is committed for sale under a long term contract at a low price of 13.82 cents per Mcf with no price redetermination clause. For this reason, if the amount of Alberta sulphur which can be marketed increases or the selling price improves appreciably in the next few years an increase in the sulphur recovery could be economically feasible.

With respect to the overall conditions of the environment in the general Harmattan Area, the Board finds as follows:

1. On the basis of the large number of complaints reported to the Board and to the Department of the Environment over the years and mentioned in submissions at the hearing, there is little doubt that the Harmattan Area has suffered significant pollution and, despite improvements of the past year or so, some problems remain.

2. The monitoring program in the general area has been and remains somewhat inadequate bearing in mind the number of pollution complaints that have been received.

3. Many of the past pollution complaints appear to relate to other operations in the area rather than to sulphur dioxide emissions from the Harmattan-Leduc plant. Many of the most serious sources of pollution have been eliminated by recent modifications to plant and field operations. There are few serious contraventions of the Board's Oil and Gas Regulations or of the conditions contained in the Approvals issued for the Harmattan Area Plant or the Harmattan Leduc Plant. The remaining identifiable problems relate largely to the completion of work started earlier and to special situations concerning operation of the wells, the flowlines, the treaters and the stock tanks as well as the two plants.

4. Specific matters requiring immediate further attention are:

   (a) A smokeless flare should be installed to control smoke emissions during plant turn-around or upsets and to accommodate the possibility of routine smoke emissions caused by matters such as vapours from the compressor suction scrubber. This matter has been the subject of several discussions between the Board staff and the operators and the necessary equipment is now on order. Installation has apparently been delayed due to limited equipment supplies.

(b) All wellbore, tubing wash treatments to clean up sulphur deposits should be directed into a completely closed system to the processing plant. This is the current practice in most instances and if made a rigid procedure would reduce the possibility of occasional releases of visible smoke at well sites.

(c) Flow line depressuring operations, to remove hydrate plugs or for other reasons, are currently carried out by directing the flow line fluids to a 100-foot well site flare stack. If liquids are present, visible smoke may result. Such depressuring should take place through separation equipment so that liquids may be collected in a stock tank and either conserved or disposed of to the underground system.

(d) The liquid hydrocarbon closed drain system at the Leduc plant terminates at a burn pit. If gathered liquids are burned off, black smoke would result. This drain system should terminate at a low pressure dump tank so that liquid hydrocarbons can be conserved. The water can be sent to the disposal system and the vapours properly vented to the flare system.

(e) Leduc gas wells should be tested directly into the flow line to the plant to avoid flaring of sour gas in the field. Even though the flaring is currently through a stack of approved height, the chances of pollution would be reduced if any necessary release of sulphur dioxide was at the plant through the permanent stacks.

(f) Low pressure treater gas and stock tank vapours have until recently been flared through a 60-foot stack at the central battery. These vapours contain some hydrogen sulphide and may be one cause of periodic complaints. The vapours should be gathered and re-injected to the high pressure gas line into the processing plant. This matter has been discussed between the operator and the Board staff and the necessary modifications are now being made.

(g) Pig traps at all satellite locations are currently bled off into pop tanks. Even though the hydrogen sulphide content is not such that this is automatically prohibited by the Regulations, the special problems in the area are such that these should be bled off into a pressure tank from which the vapours could be flared in a controlled manner.

(h) Produced water and liquid hydrocarbons at the Harmattan Leduc Plant are currently stored in tanks. A system exists for directing the tank vapours to a 150-foot flare stack in accordance with the Regulations. Because of the back pressure on the stack, the tank vapours are not being fed continuously to the stack. Some method such as a venturi or eductor system should be installed to collect these vapours and direct them to the stack to ensure efficient flaring.

(i) The measurement facilities at the Leduc Plant are such that the volumes of sweet gas added to acid gas to ensure complete combustion when flaring takes place, are not measured but are estimated. Bearing in mind the pollution problems in the area this is not satisfactory and should be corrected by installing appropriate measurement equipment.

DECISION

Based on the evidence presented at the hearing and its own investigation, the Board is convinced that production operations in the Harmattan Elkton Field and processing operations at the Harmattan Leduc Gas Plant and at the Harmattan Area Plant must be improved immediately. By separate letter to the operators in the area, the Board is requiring that the detailed actions listed in the Findings of this decision be completed to the satisfaction of the Board not later than October 1, 1972. To ensure that the Provincial Regulations respecting ground level concentrations of sulphur dioxide are not contravened, the Board also requires that the operators of the Harmattan Leduc Plant increase the monitoring in the area to the satisfaction of the Board and the Department of the Environment. (The Board is also requesting that the Department of the Environment increase its monitoring surveillance in the general area.) If, following resolution of the aforementioned operating problems, the monitoring results and other surveillance show that a pollution problem continues to exist in the area, the Board will require further appropriate action.

With respect to the specific application of Canadian Superior for exemption of the Harmattan Leduc Plant from the sulphur recovery efficiency guidelines, the Board believes that exemption is warranted having regard to the extremely unfavourable current economic circumstances and the relatively small decrease in emission of sulphur to the atmosphere of some 5 tons per day which would be achieved by increasing recovery from 95 to 96 per cent. Accordingly, the Board grants the application. If the amount of sulphur which can be marketed or the selling price improves appreciably in the next few years, the Board will review the economics of the Harmattan Leduc sulphur producing operations and may require increased sulphur recovery.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Board Member

Dated at Calgary, Alberta
June 21, 1972

ENERGY RESOURCES CONSERVATION BOARD

Decision 72-9
Application No. 6224

TRANSMISSION LINE - BARRHEAD TO SARAH LAKE

INTRODUCTION

The subject application was made under sections 9, 11 and 14 of The Hydro and Electric Energy Act by Alberta Power Limited for a permit to construct, a licence to operate and an order to connect an electrical transmission line from the Calgary Power Ltd. substation located at the South-west quarter of Section 1, Township 60, Range 4, West of the 5th Meridian to the South-east quarter of Section 13, Township 65, Range 11, West of the 5th Meridian.

A hearing of a portion of the application involving the location of the transmission line in Townships 62 and 63, Ranges 6 and 7 West of the 5th Meridian, was held in Barrhead on September 6, 1972 by Mr. Vernon Millard, Vice Chairman and Mr. J. I. Strong, P. Eng., Board Member.

The following appeared at the hearing:

	Represented by	Witnesses
Alberta Power Limited	Mr. Thomas	D.A. Peterson, P.Eng. D.J. Flory, Superintendent of Land and Properties, Alberta Power Limited

Interveners Representing Themselves:

P. Dabels
G. Lockhart
W. Charney
Floyd Olson
K. Kuelken
Raymond Olson

Board Staff:

A. McLarty, Assistant Board Solicitor
D. Wood, P. Eng.

THE BACKGROUND TO THE APPLICATION
AND THE APPLICATION

The purpose of the proposed transmission line, as outlined by the applicant, is to serve the expanding oil field electric energy requirements in the Swan Hills area. The transmission line will be a 144 KV line having a maximum capacity of 82 MW and will be the main feeder to the Swan Hills area, being supplemental to several 72 KV lines presently in use. The area to be served is in the Alberta Power Limited service area. Electric energy for this line is to be obtained at the Calgary Power substation at Barrhead because of its available capacity.

It is the policy of the Board to publish notice of an application for a permit to construct a transmission line for which the applicant has not acquired the right of way.

Following this policy the Board advertised the subject application for objections by a notice published on May 4, 1972. The Board received objections from three land owners all owning land in Township 62, Range 7, West of the 5th Meridian. Alberta Power spent some considerable time attempting to resolve the objections of the three land owners but was unsuccessful, and the Board therefore decided to call a hearing.

Notice of the hearing to be held on the contentious part of the application was published on August 4, 1972 with copies of the notice mailed to owners and occupants of the adjoining lands at the same time. Since only a limited portion of the route was in contention, and in view of the need to have the line in operation by later this year, the Board issued Permit No. AP 72-3 approving that portion of the application to the south and north of the contentious area in Townships 62 and 63, Ranges 6 and 7, West of the 5th Meridian.

A letter, dated August 25, 1972, bearing the signatures of seven land owners objecting to the proposed route in Townships 62 and 63 was received by the Board.

Mr. H. S. Borg, who was one of the three original objectors wrote the Board on June 7, 1972 advising that an understanding had been reached with the applicant about several items including trespass and right of entry. Mr. Borg was later notified of the hearing and replied that he did not intend to appear before the Board.

Appendix #1 shows the proposed routes with possible alternates including one suggested by Alberta Government Telephones and one by the interveners.

DEFINITION OF THE ISSUES

The Board is required under the terms of The Hydro and Electric Energy Act to secure safe and efficient practices in the public interest in the transmission and distribution of electric energy.

The main issue is whether the location of the transmission line is satisfactory having regard for the interests of the land owners and the needs of the utility company to serve the public interest in a safe and efficient manner.

VIEWS OF THE APPLICANT

The applicant's submission outlines the need for this transmission line to be in operation by October of 1972 in order to handle the increasing electric energy requirements and, in particular, the projected winter peak load in the Swan Hills area. Data was supplied to the Board stating that the applicant had opened each existing transmission line separately and observed that the voltage drop on the system was considerably in excess of the 10 per cent that the voltage regulators could handle. This results in very unsatisfactory operating conditions throughout the system and requires a new feeder at the earliest possible date.

Alberta Power stated that in selecting a transmission line route it preferred a location on an existing highway right of way or as near to a regular highway or road allowance as possible to enable access for servicing purposes. Its initial selection, therefore, was to locate on the existing highway right of way as shown on the plan in Appendix #1, Route #1.

Alberta Government Telephones objected to this route because of a conflict with both existing and proposed telephone lines. The proposed transmission line would cause problems and specifically electromagnetic interference with the A.G.T. lines.

Alberta Government Telephones suggested an alternate route shown as Route#2 in Appendix #1, commencing at the mid-point on the west centre boundary of Section 10, Township 62, Range 6, West of the 5th Meridian proceeding straight north 2½ miles,

then west along the north boundary of Section 21 and 20 to the road allowance. Alberta Power was of the opinion that this route would not only interfere with more land owners and their dwellings but would add one mile in extra length to the proposed line at a cost of approximately $15,000.

Alberta Power, as a result, proposed in its application the present route designated as Route #3 in Appendix #1 which would follow the right of way of an existing pipe line and which runs diagonally across the land of several of the owners. It stated that this route was the shorter route and would affect the least number of land owners, but because of its diagonal location across the respective sections of land it would not be as accessible as the highway route.

Alberta Power also considered an alternate route suggested by the interveners which would by-pass all of the present interveners and is shown as Route #4 in Appendix #1. This route, after crossing the Athabasca River, would turn north and proceed northerly on the half section line through the middle of Sections 2, 11, 14, 23, 26 and 35 to the north boundary of Section 35, then westerly on the north boundary of Sections 35, 34, 33, 32, 31, Township 62, Range 6, West of the 5th Meridian and Sections 36 and 35, Township 62, Range 7, West of the 5th Meridian to intersect with the applicant's proposed route.

Alberta Power submitted that this route was not acceptable as it would be 3.2 miles longer and would cost approximately $43,000 more than the route it proposed. In addition it would affect as many or more land owners, and because it would pass through the mid-section point of several sections, accessability would also be poor.

At the hearing Alberta Power indicated that it was prepared to consider modest changes in the proposed route in order to accommodate some of the objections. The hearing was adjourned for a short period to give the applicant and the interveners the opportunity of discussing an alternate route. Alberta Power and the interveners then reported to the Board that they had reached a possible agreement, and outlined an alternate proposal. As this route involved some additional owners, a week was granted to the applicant to obtain the consent of these owners in order to satisfy the majority of the land owners who would be affected by the existing and proposed route.

VIEWS OF THE INTERVENERS

Messrs. P. Dabels, G. Lockhart, W. Charney, Floyd Olson, K. Kuelken and Raymond Olson objected to the proposed route on the basis that

(1) angle crossing of arable land is wasteful and unnecessary,

(2) farming around poles involves extra time and labour,

(3) line clearing for the power line will reduce windbreaks,

(4) Route #4 in Appendix #1 would not affect farm buildings or angle across farm land, and

(5) there was no guarantee that another line would not be built on this right of way in the future.

Of the interveners who gave their views at the hearing four of them were principally concerned by the diagonal or angular location of the proposed right of way across their respective properties. They preferred the transmission line to be right angle locations located adjacent to section or half section lines to minimize interference with farming operations.

The other interveners were principally concerned with the amounts of compensation offered for the easements across their property. At the hearing the Board advised that compensation was a matter that did not come under this Board's jurisdiction and was the responsibility of the Board of Arbitration, under The Right of Entry Arbitration Act.

VIEWS OF THE BOARD

The Board accepts the submission that additional transmission capacity from the Calgary Power substation at Barrhead to Sarah Lake at 144 KV or higher voltage is necessary, and further that such is required to be installed by the fall of 1972 in order to adequately serve the increasing load in the Swan Hills area.

The Board believes that from the evidence submitted that the proposed route is not completely satisfactory having regard for the interests of the land owners.

The Board has subsequent to the close of the hearing been notified by letter, that the applicant has negotiated an alternate route through Township 62, Range 6 to the satisfaction of the majority of the landowners involved. The extent of this alternate location is shown as Route #5 in Appendix #1. Supporting documents with Alberta Power's letter indicate that the four main objectors to the route of the transmission line as proposed at the hearing have signed easements with regard to the revised route of the north portion of the line.

Several owners to the south of the proposed rerouting have not yet signed easements but at the hearing they advised that they were primarily concerned with the amounts of compensation to be paid which is a matter for another Provincial Board.

DECISION

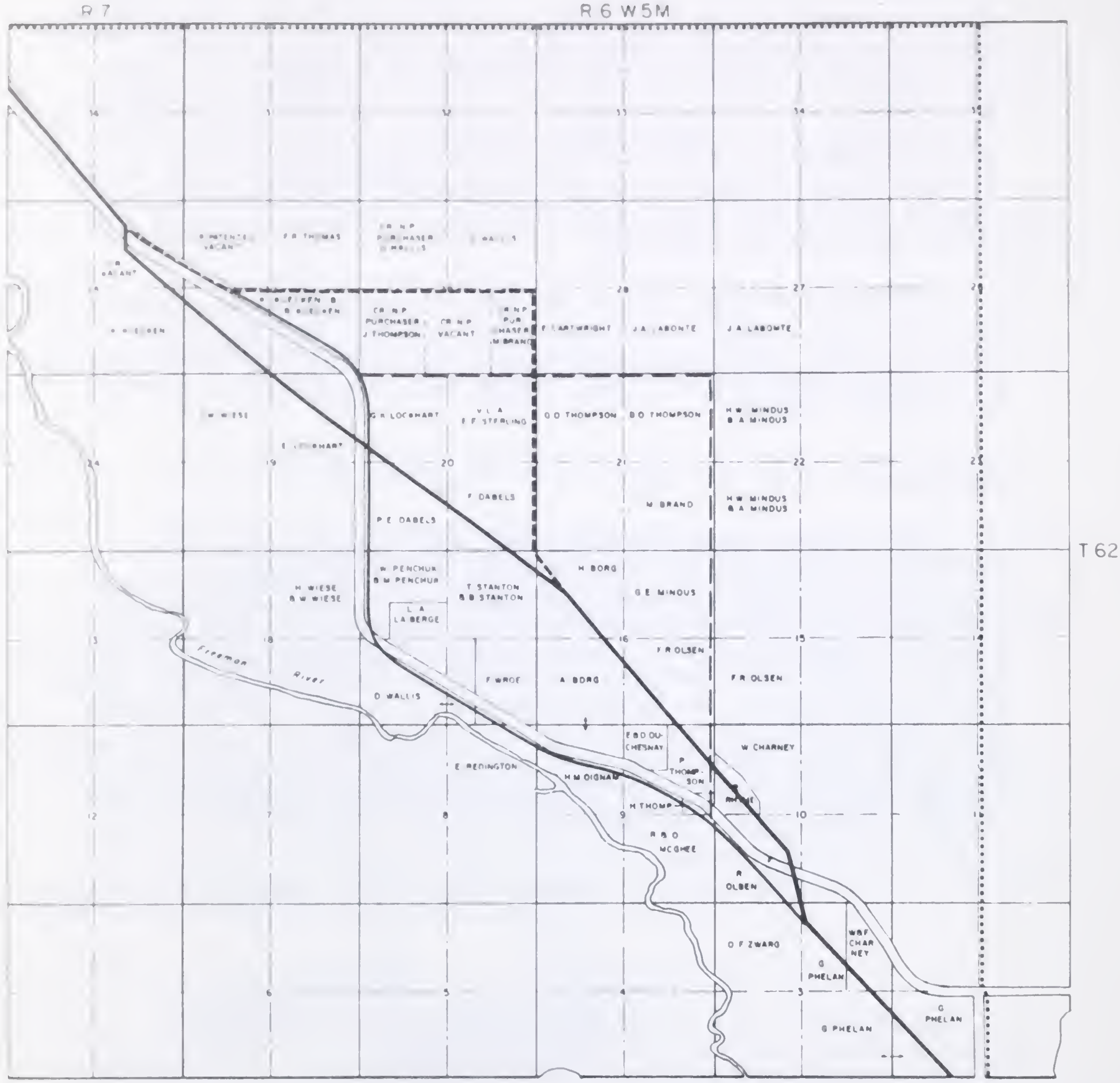
The Board, upon considering the application, the evidence submitted at the hearing and the material subsequently submitted by the applicant has decided that the route of the transmission line through Townships 62 and 63, Ranges 6 and 7, West of the 5th Meridian shall be as shown as Route #3 amended by Route #5 in Appendix #1. The route adopted by the Board follows as nearly as possible that negotiated by the applicant. The Board is of the opinion that the route selected will best serve the public interest, the interest of the interveners and other concerned land owners as well as the interests of the applicant.

ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard

Vernon Millard
Vice Chairman

DATED at Calgary, Alberta
October 2, 1972.



PROPOSED 144KV TRANSMISSION LINE ROUTES

1 ———— ROUTE ORIGINALLY PROPOSED BY ALBERTA POWER LIMITED ALONG EXISTING HIGHWAY
2 — — — ROUTE SUGGESTED BY ALBERTA GOVERNMENT TELEPHONES
3 ━━━━ ROUTE PROPOSED BY ALBERTA POWER LIMITED ALONG PIPE LINE
4 ·············· ROUTE SUGGESTED BY INTERVENERS
5 - - - - - - - ALTERNATE PROPOSAL

DECISION 72-9   APPLICATION # 6224

APPENDIX # 1

ENERGY RESOURCES CONSERVATION BOARD
CALGARY ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

Decision 72-10
Application No. 6351

APPLICATION FOR CONCURRENT PRODUCTION AND GOOD PRODUCTION PRACTICE CROSSFIELD EAST ELKTON POOLS

THE APPLICATION AND HEARING

Amoco Canada Petroleum Ltd. on behalf of itself and the East Crossfield Elkton Working Interest Owners applied in accordance with Section 38 clause (e) of the Oil and Gas Conservation Act for approval of a scheme to produce concurrently the crude oil accumulation and its associated gas cap in the Crossfield East Elkton A Pool (now designated the Crossfield East Elkton A Pool and Crossfield East Elkton D Pool).

Amoco Canada Petroleum Ltd. on behalf of itself and Canadian Reserve Oil and Gas Ltd. also applied for approval to produce the crude oil accumulations of the Crossfield East Elkton A Pool and Crossfield East Elkton D Pool in accordance with good production practice with the maximum daily rate limited to 500 stock tank barrels of crude oil per well and the maximum daily withdrawal from the two pools limited to 3000 stock tank barrels of crude oil.

An intervention was filed by Saucier, Jones, Black, Gain, Stratton and Laycraft on behalf of Canadian Reserve Oil and Gas Ltd. for the purpose of proposing some alternate recommendations.

Canadian Superior Oil Ltd. and Pacific Petroleums Ltd. intervened for the purpose of cross-examination only.

The application was heard on August 9, 1972, by the Board, with D. R. Craig, P. Eng. and V. Millard sitting.

APPEARANCES

The following appeared at the hearing:

	Presented by	Abbreviation Used in Report
Amoco Canada Petroleum Ltd.	Dr. T. D. Stacy, P. Eng. E. H. Toews, P. Eng. C. M. Richard, P. Geoph. T. M. Shier, P. Geol.	Amoco
Canadian Reserve Oil & Gas Ltd.	H. J. Gleusteen, P. Eng. J. F. Curran (Saucier, Jones, Black, Gain, Stratton & Laycraft)	Canadian Reserve
Canadian Superior Oil Ltd.	J. Peake, P. Eng.	Canadian Superior

	Presented by	Abbreviation Used in Report
Pacific Petroleums Ltd.	R. Paul, P. Geol. R. Macauley, P. Eng.	Pacific
Energy Resources Conservation Board	R. G. Evans, P. Eng. G. R. Heming, P. Eng. A. R. Mustafa	Board Staff

BACKGROUND

The Crossfield East Wabamun A Pool (hereinafter called the D-1 Pool) and the Crossfield East Elkton A Pool were discovered in 1960. Further drilling resulted in the discovery of the Crossfield East Elkton B Pool and Crossfield East Elkton C Pool (hereinafter called the Elkton B Pool and Elkton C Pool respectively). Several years of production performance from the Crossfield East Elkton A Pool indicated that it was in fact three separate hydrocarbon accumulations. As a result the Crossfield East Elkton A Pool was divided into three pools and were designated the Crossfield East Elkton A Pool, Crossfield East Elkton D Pool and Crossfield East Elkton E Pool (hereinafter called the Elkton A Pool, Elkton D Pool and Elkton E Pool respectively) effective August 1, 1972.

The East Crossfield Unit was formed in March 1964 and included the gas reserves of the D-1 and all Elkton Pools and provided an arrangement whereby the Elkton gas reserves would be produced at a rate based upon the combined Elkton and D-1 gas reserves. A gas processing plant was constructed to process some 38 million cubic feet per day (MMCFD) of sweet Elkton gas. In February 1965, production commenced from the Elkton A and Elkton D Pools. In late 1970, the Elkton plant was expanded and is now capable of processing 57 MMCFD of gas. A second gas processing plant capable of processing 122 MMCFD was constructed to accommodate the sour D-1 Pool gas and in February 1968, production commenced from the D-1 Pool. The D-1 Pool has produced approximately 120 MMCFD of gas since 1968, resulting in 55 MMCFD of sales gas. However, the plant was not designed with sufficient capacity to process the contract sales gas rates of 70 MMCFD from the D-1 zone so the Elkton pools continued to deliver approximately 15 MMCFD of gas on behalf of the D-1 Pool. Amoco estimated that at December 31, 1971, some 30 billion cubic feet of gas had been produced from the Elkton pools on behalf of the D-1 Pool.

After several years of production from the Elkton zone, there appeared to be a darkening in the color of the condensate and an increase in its specific gravity indicating that crude oil was being produced along with the gas and condensate. However, no tests were made on the lower section of the pay zone to determine whether there was a significant crude oil accumulation until the well in 10-14-28-1 W5M was recompleted from the D-1 Pool to the Elkton formation in January 1971. On test, the well produced at 1600 barrels of crude oil per day at a gas-oil ratio of 2300 cubic feet per barrel.

Upon recognizing the significance of the crude oil accumulation, Amoco attempted to unitize the crude oil and gas ownerships. When these attempts failed, the subject application for concurrent

production and good production practice was made to the Board.

THE NATURE OF THE RESERVOIRS

The Crossfield East Elkton pools, in the Turner Valley Formation, lie on a monoclinal stratigraphic trap dipping gently westward at less than one degree. The porosity is intercrystalline and vuggy. The limits of the reservoirs are determined by permeability barriers, entrenched erosional channels and an updip erosional truncation. The average original gas-oil contacts of the Elkton A Pool and Elkton D Pool oil zones were 3928 feet subsea and 3962 feet subsea respectively. No known aquifer is present in any of the pools.

Currently there are five Elkton pools declared in the Crossfield East Field. The Elkton A Pool and Elkton D Pool each contain a crude oil accumulation along with an associated gas cap. The Crossfield East Elkton B Pool contains only crude oil. The Crossfield East Elkton C Pool and Crossfield East Elkton E Pool are non-associated gas reservoirs and contain approximately 15 billion cubic feet (BCF) and 2.6 BCF of gas respectively (See Attachment #1). Only the Elkton A Pool and Elkton D Pool which contain both crude oil and gas are considered directly relevant to this application.

Gas and crude oil production from the Elkton A and Elkton D Pools in the last 7 years has resulted in a decline in reservoir pressure from initial values of over 3000 psia to pressures in 1500 - 1700 psia range. As a result of this decline in pressure, some of the gas that was in solution in the oil zone has been released. Some of the gas production to date has been solution gas and some of the liquid produced with the gas has been crude oil.

DEFINITION OF ISSUES

The concurrent production of a crude oil accumulation and its associated gas cap normally results in a lower recovery of crude oil than if the gas cap production was deferred until the crude oil had been recovered. The Crossfield East Elkton pools were developed and gas processing facilities installed on the basis that there was not a significant crude oil accumulation. In dealing with this application, the Board is concerned, on one hand, with the possible impact on investments made under the then prevailing conditions if a change in production procedures were to occur and, on the other hand, with the effect of continued gas cap production on the crude oil recovery from these pools. Having regard for these special circumstances the Board is also concerned with the alternate means of maximizing crude oil recovery should concurrent production of the gas cap appear reasonable. In order to resolve these matters it is necessary to have a reliable interpretation of the size and fluid content of the reservoirs.

The main issues of the application are:

(1) the quantities of crude oil, gas and condensate produced to date,

(2) the size of the crude oil accumulation and gas cap,

(3) the desirability of continuing concurrent production,

(4) alternate depletion schemes to maximize crude oil recovery.

CRUDE OIL, GAS AND CONDENSATE PRODUCED TO DATE

In order to perform reservoir engineering calculations and to determine royalties, the volumes of crude oil, gas and condensate that have been produced to date must be established.

(1) Views of Amoco

Amoco estimated that some 1,822,000 stock tank barrels of crude oil, 2,003,000 stock tank barrels of condensate and a net 68.0 billion cubic feet of gas (gas cap and solution gas minus injected gas) had been produced from the Elkton A and Elkton D pools to the end of 1971. The portion of the produced liquids that was condensate was estimated from a "condensate yield curve." (See Attachment #3).

Amoco also indicated that another approach to determine the proportions of condensate and crude oil in the liquid production had been attempted using mixing curves but the method was not considered to be as accurate because of the lack of regular and reliable surface fluid analysis since 1965. As a result Amoco planned to employ Core Laboratories Canada Ltd. to make some additional studies to determine the nature of the reservoir fluids as they existed initially in the reservoir.

Amoco also stated that when an acceptable method of determining the ratio of condensate to crude oil had been obtained, amended production records would be submitted to the Board and that because crude oil is a non-unitized substance, some adjustment may be required in the royalty payments. Amoco advised that it was reviewing the documents relating to the leases and expected to bring the matter before the working interest owners in due course.

(2) Views of the Board

The Board agrees with Amoco that there is not now a satisfactory means of estimating crude oil production from the Elkton A and Elkton D Pools. The Board believes that further analysis such as the proposed study by Core Laboratories Canada Ltd. is necessary to resolve this issue. For the purposes of this report, the Board has adopted the production figures proposed by Amoco based on the condensate yield curve.

THE CRUDE OIL AND GAS IN PLACE

(1) Views of Amoco

Amoco constructed a plot of P/Z versus cumulative raw gas cap production for each of the pools in order to determine the original gas cap volumes. These gas cap volumes were then adopted for material balance calculations to determine an original crude oil in place for the Elkton A and Elkton D Pools of 45,000,000 stock tank barrels. (See Attachment #5). Amoco recognized the sensitivity of the material balance calculations to small changes in gas cap volume, formation volume factors and crude oil production, but felt that the resultant errors would be com-

pensating and that overall, the proposed volumes were accurate within $\pm$ 10%.

Amoco also made a volumetric estimation of crude oil and gas in place based on seismic data. Amoco wished to keep the basic seismic data confidential for the present time and presented only derived gross and net pay isopachs for the Elkton. The volumes estimated from these maps indicate a slightly smaller gas cap volume and a slightly larger crude oil zone volume (by about 2,000,000 stock tank barrels) than was obtained by material balance calculations. Amoco felt quite confident in its seismic data and has, based on this information, drilled two new wells, is drilling a third and stated that it may drill two more in order to substantiate its estimated crude oil volume and to achieve a better crude oil recovery.

(2) Views of the Board

The Board investigated the magnitude of possible errors in the data that are input to the material balance equation and the sensitivity of the material balance equation to these possible errors. The most serious of these is the size of the gas cap where a change of 10% will result in a change in calculated oil in place of some 40%. As a result, the Board concluded that it can not place much reliance on the results of the material balance calculations in these pools because of the high degree of uncertainty in the basic data.

The Board's volumetric estimates of proven reserves, based solely on well data, indicate a significantly smaller crude oil in place than proposed by Amoco. These data are tabulated on Attachment #5. However, the Board accepts Amoco's view that there is a reasonable chance of a significant volume of crude oil existing in the down-dip portion of these pools. Having regard for the Board's responsibility for ensuring conservation of the remaining crude oil and gas reserves, the Board has adopted the higher crude oil and gas cap volumes proposed by Amoco for the purpose of considering the effects of concurrent production on the recovery of the crude oil.

THE DESIRABILITY OF CONTINUED CONCURRENT PRODUCTION

(1) Views of Amoco

Amoco pointed out that, because crude oil is not a unitized substance in the East Crossfield Elkton Unit, the Crude oil zone will have to be developed independently by the owners of the individual tracts. Amoco contended that wells should be drilled on the western flanks of the reservoirs as soon as possible because the rapidly declining reservoir pressure would soon make development of the crude oil zones uneconomical.

Amoco submitted that total investment to date in the Elkton and D-1 gas production and processing facilities by the Gas Unit is in the order of \$36 million of which \$6 or \$7 million are for the Elkton facilities and \$29 or \$30 million for those of the D-1.

Amoco contended that because of the large capital investment by the Gas Unit owners to date, continued gas cap production at a reasonable rate was justified. In order to evaluate the losses in

crude oil recovery due to continued gas cap production and prorated oil allowable rates, Amoco made a study of the variation in crude oil recovery under different depletion schemes based upon the Tracy form of the material balance equation. Predicted recoveries ranged from 8.8 percent for the case of concurrent gas cap blowdown and prorated oil production to 35.0 per cent for repressuring the gas cap and producing the crude oil zone under good production practice at a rate of 4000 barrels of crude oil per day. The results of this study are summarized on Attachment 2.

In order to maintain a reasonable cash flow to the gas unit owners and yet attain a reasonable crude oil recovery, Amoco proposed a cut back in gas cap production to 20.8 MMCFD from an average rate of 37.0 MMCFD in 1971. The proposed rate was based upon a rate of take of 1 MMCFD for each 8.4 BCF reserve and the total sales gas reserve of 157.2 BCF recognized by the gas purchaser. This gas reserve figure included some 34.2 BCF of solution gas from the Elkton A and Elkton D Pools as well as the total recoverable free gas in all five Crossfield East Elkton Pools. Based on this gas production rate, Amoco predicted crude oil recoveries in the range of 8.8 to 12.7% for a prorated oil rate and a 3000 BOPD good production practice rate respectively.

(2) Views of the Board

The Board attempted to evaluate the effect of continued gas cap production on the recovery of crude oil using a one dimensional mathematical reservoir simulator. Due to the present uncertainties in reservoir configuration, a lack of accurate historical production data and the inability of the model to account for gas coning, only limited reliability can be placed on the absolute values of the predicted crude oil recoveries. However, on a relative basis, they indicate that crude oil recovery is particularly sensitive to the rate of gas cap production. Based upon an assumed crude oil in place of 45 million barrels, the study suggests that if gas production were reduced from the current gas production rate of 37 MMCFD to 20.8 MMCFD as proposed by Amoco, an increase in oil recovery of some 3 million stock tank barrels would be realized. The Board accepts that crude oil recovery would be improved by restricting gas production in this manner but does not believe that the improvement is sufficient. The Board's studies indicate that approximately 6 million stock tank barrels of additional crude oil recovery would be recovered by reducing gas production from 20.8 MMCFD to something approaching solution gas only (5 MMCFD). Should the crude oil reserves turn out to be considerably less than the 45 million stock tank barrels estimated by Amoco, these potential gains would be reduced accordingly.

Having regard for the significant effect that gas cap production has on crude oil recovery, the Board believes that, in the interests of conservation, production from the gas cap of the Elkton A and D pools should be minimized. In reviewing the production that has occurred in the Crossfield East Field to date, the Board notes that during the seven years since production was initiated, the Elkton A and D Pools have contributed to the total gas production from the unit to a degree disproportionate to the reserves. On a marketable reserve basis the A and D Pools represent nearly 20 per cent of the reserves in the gas unit, with the Wabamun A pool representing nearly 80 per cent. In contrast, the Elkton A and D Pools have to the end of 1971 accounted for 44 per cent of the marketable gas produced by the unit as compared

to 53 per cent by the Wabamun A Pool. The fact that the Elkton A and D Pools contributed so heavily to the total unit production during this period and in effect produced on behalf of other pools in the Unit was responsible for the very significant decline in reservoir pressure from some 3,000 psi to about 1,500 psi. This rapid decline has already had an unfavorable impact of crude oil recovery and if permitted to continue would have a serious effect on the ability of the crude oil owners to develop and recover a reasonable portion of the remaining crude oil reserves.

The Board is cognizant of the investment in the existing processing plant and the desirability of keeping it in economic operation. This is especially true because of the difference in ownership between the crude oil and gas interests in the Elkton A and D Pools. However, the Board believes that henceforth, maximum reliance for plant processing gas should be placed on the other Elkton pools and the solution gas produced in conjunction with crude oil in the A and D Pools. The Board believes that the Crossfield East Elkton C Pool could produce at a rate of some 10 MMCFD and that an additional minor volume might be available from the E Pool. It is difficult to estimate the solution gas production from the A and D Pools because of uncertainty with respect to the number of wells to be drilled and the rate of crude oil production. The Board believes that it would be reasonable to assume that during the next year or two some 3 to 5 MMCFD of gas would be unavoidably produced from wells producing crude oil. On the basis of these estimates the Board concludes that the Elkton sweet gas processing plant could be supplied with some 15 MMCFD of gas. The Board estimates that this would provide an economic level of operations.

The Board recognizes that there is considerable uncertainty respecting the extent of the oil accumulation and believes that a definitive assessment of appropriate gas production rates is not possible at this time. However, on the basis of the foregoing, the Board concludes that continued concurrent production is desirable and that conservation of all gas unavoidably produced with crude oil will provide a rate of gas production from the Elkton A and Elkton D pools of 2 MMCFD and 3 MMCFD respectively for the next year or two. These rates are interim but will provide the necessary time for the evaluation of the crude oil reserves and alternate depletion schemes.

ALTERNATE DEPLETION SCHEMES TO MAXIMIZE CRUDE OIL RECOVERY

(1) Views of Amoco

Amoco estimated the cash flow to the owners of the Elkton A and Elkton D pools for each of the various depletion schemes which were studied. The results are tabulated on Attachment 2. Amoco indicated that continuation of the current method of operations or development under prorated crude oil allowables, was not in the best interests of conservation or economics.

Amoco's study indicated that the recovery of crude oil would be adversly affected by a high rate of gas cap withdrawal, but that it could be increased by a crude oil withdrawal rate higher than that

permitted under the proration system. Amoco therefore proposed a scheme of good production practice with a maximum daily well production of 500 stock tank barrels of crude oil and a maximum daily production of crude oil from the two pools of 3000 stock tank barrels. Amoco also stated that if the crude oil rate was limited to the prorated allowable, there would be insufficient incentive to continue drilling on the western flank and, as a result, much of the postulated crude oil there would remain unrecovered.

Amoco studied several schemes of enhanced recovery by pressure maintenance, each of which indicated significantly higher recoveries of oil. On a preliminary basis the studies indicated that a scheme of re-pressuring might be feasible. However, Amoco stated that the western extent of the reservoir would have to be determined by drilling before a meaningful reservoir study could be undertaken to substantiate the feasibility of enhanced recovery by pressure maintenance.

(2) Views of Canadian Reserve

Canadian Reserve expressed general support of Amoco's application but proposed an alternate recommendation. Claiming that its objectives were to establish more accurately the optimum crude oil and gas rates required for simultaneous depletion and to obtain the data necessary to evaluate well productivity, coning characteristics and to further substantiate the crude oil in place, Canadian Reserve proposed an interim testing period of six months during which individual oil wells would be produced at a maximum rate of 1500 barrels of crude oil per day. During the later stages of this test period, reservoir simulation studies would be conducted to determine optimum withdrawal rates.

(3) Views of the Board

The Board's studies and those of Amoco indicate that under a concurrent depletion scheme, crude oil recovery is somewhat dependent upon the rate of crude oil production although not to the extent that it is on the rate of gas cap production. It is also dependent upon the implementation of enhanced recovery operations. Crude oil production rates above those allowed under the proration plan would improve the crude oil recovery. In view of this and in order to provide the necessary incentive to drill for and recover the potential crude oil reserves in the western portion of the reservoirs, the Board believes that provision for special crude oil allowables in these pools is warranted.

The Board believes that the rates proposed by Canadian Reserve for the six month test period are excessively high and could lead to premature gas coning and a reduction in crude oil recovery. On the other hand, prorated allowable rates would also lead to a lower crude oil recovery. The Board agrees with Amoco that an individual well production rate of 500 barrels of crude oil per day would provide a rate sufficiently high to ensure improved crude oil recovery while acting as an incentive to drill and develop the crude oil in the western flank of the pools before further pressure decline in these pools due to gas cap production makes crude oil recovery impractical. However, the Board

believes that at this high well allowable, there should not be any allowance made for individual well incapability.

The Board believes that imposing a daily maximum crude oil production rate of 3000 stock tank barrels for the two pools would be unnecessarily restrictive and, if the oil zone is extensive, could nullify drilling incentives. A maximum daily crude oil production rate of 5000 barrels for the Elkton A Pool and the Elkton D Pool appears to be more reasonable. This maximum rate will be divided between the two pools on a basis of proven oil reserves when development is completed. The impact of these increased rates on the provincial allowable is expected to be in the order of 0.5% and therefore is not considered to be of significant impact. The Board's estimate of crude oil recovery resulting from this method of depletion is shown on Attachment #2.

The Board's estimates of cash flow confirm those of Amoco that progressive restriction in gas production is favorable not only to the recovery of crude oil but also to the present worth value of cash flow.

The Board considers that pressure maintenance in these pools may be desirable if future drilling substantiates Amoco's estimated volume of crude oil in place. As a result, the Board will be reviewing all new drilling and production data from these pools and will require a detailed study on the feasibility of a scheme of enhanced recovery by pressure maintenance for these pools. In considering the feasibility of such a scheme, the Board would have regard for increased crude oil recovery, improved productivity and the effect of the scheme on gas recovery. It would not judge the scheme's economic feasibility solely on its effect on the subsisting allowed rates of crude oil production.

DECISION

The Board grants Amoco's application for approval of a scheme for the concurrent production of the crude oil accumulation and its associated gas cap in the Crossfield East Elkton A Pool and the Crossfield East Elkton D Pool, subject to the following:

1) Effective November 1, 1972, crude oil may be produced on a good production practice basis subject to a limitation of 500 barrels of crude oil per day per well. This allowed rate of production will not be affected by the incapability of other wells in the pools.

2) The average gas production rate (gross solution gas produced plus gas cap gas produced less gas returned to the formation) shall not exceed 2.0 million cubic feet per day for the Crossfield East Elkton A Pool and 3.0 million cubic feet per day for the Crossfield East Elkton D Pool, administered on an annual basis commencing January 1, 1973 and not subject to review before January 1, 1974.

3) Amoco shall conduct a study into the feasibility of enhanced recovery by pressure maintenance for these pools and submit this study to the Board before December 31, 1974.

4) Amoco shall file a copy of a study on the nature of the initial reservoir fluids by April 1, 1973. Also, revised production records will be required for Elkton A and Elkton D pools and shall be submitted as soon as possible after the completion of this study.

5) The good production practice maximum rate of 500 barrels of crude oil per well per day is not subject to review until January 1, 1976 unless it is found to significantly affect the conservation of crude oil. The Board is prepared to reconsider the rate of gas production when the delineation of the crude oil reserves and the feasibility study required under part 3 are completed.

6) The licensee of each well producing solution gas or gas cap gas in the Elkton A Pool or Elkton D Pool shall gather the gas produced from the well and shall process any gas not required for lease fuel for the extraction of natural gas liquids and dispose of the products of such processing including the marketable gas, or inject any gas not authorized under part 2 or used for lease fuel, into the formation of origin for storage.

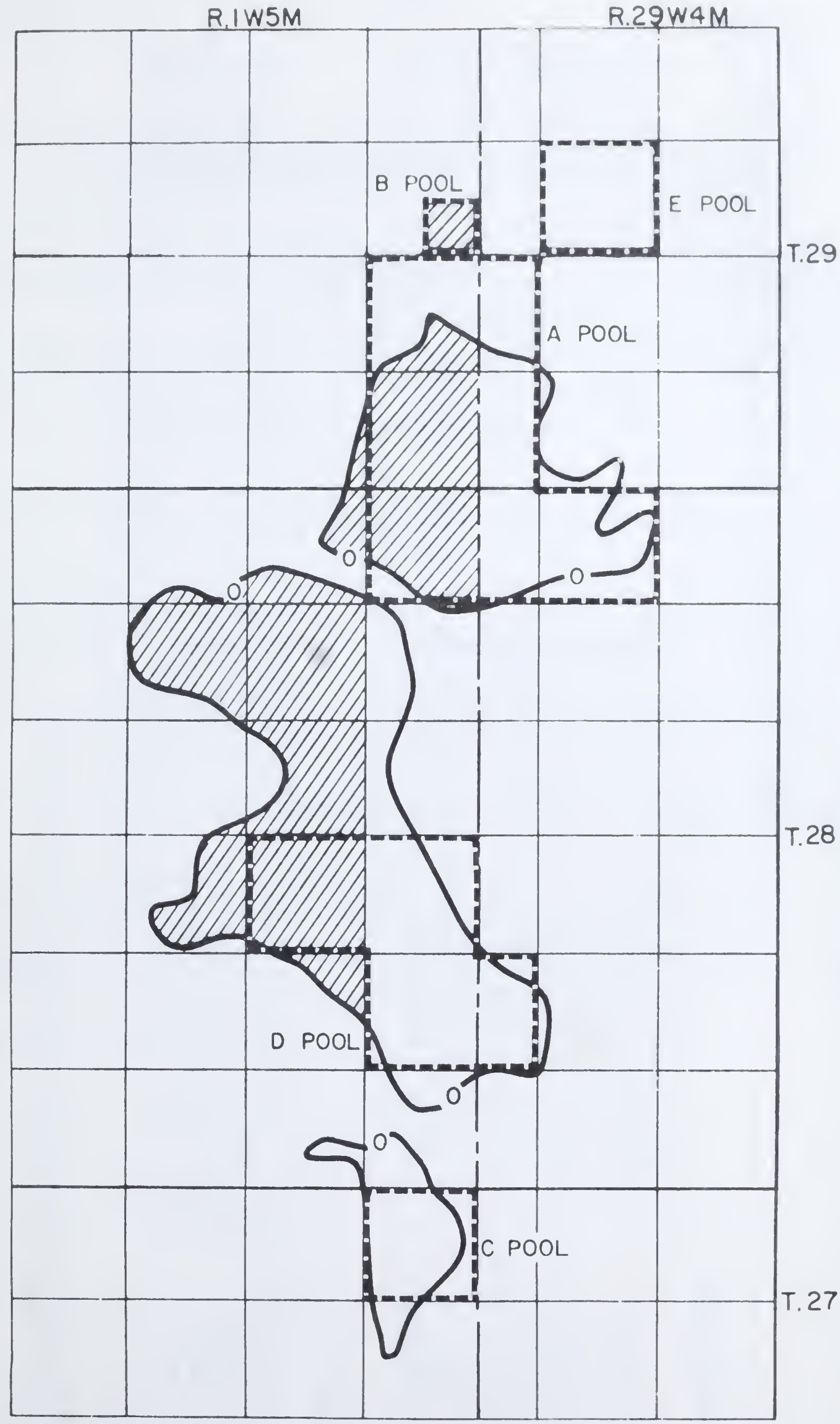
7) These terms and conditions are specified in Approval No. 1783 A and Approval No. 1784 A issued concurrently with this decision.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

V. Millard
Vice Chairman

Dated at Calgary, Alberta, October 7, 1972.



CROSSFIELD EAST ELKTON POOLS

APPROXIMATE AREAS OF CRUDE OIL OCCURANCE

ENERGY RESOURCES CONSERVATION BOARD
CALGARY, ALBERTA

Attachment 2.

CROSSFIELD EAST ELKTON A AND D POOL
CRUDE OIL AND GAS DEVELOPMENT

Recovery and Cash Flow Comparison

			Remaining Recoverable Crude Oil Reserve (STB)	Total Crude Oil Recovery (%)	Cash Flow Before Income Tax PW @ 10% ($)
	Amoco's Submission				
1. a)	Base Case	- Continued Operations	1,091,000	6.5	7,776,000
b)	Gas Cap Blowdown	- Prorated Oil Rates	2,106,000	8.8	8,239,000
2.	Gas @ 20.8 MMCFD	- Prorated Oil Rates	2,106,000	8.8	8,268,000
3. a)	Gas @ 20.8 MMCFD	- G.P.P. @ 1500 BOPD	3,037,000	10.9	10,086,000
b)	Gas @ 20.8 MMCFD	- G.P.P. @ 2000 BOPD	3,311,000	11.5	10,686,000
c)	Gas @ 20.8 MMCFD	- G.P.P. @ 3000 BOPD	3,859,000	12.7	11,893,000
4.	Gas Cap Shut-in 2½ yrs	- G.P.P. @ 2000 BOPD	5,411,000	16.1	12,382,000
5. a)	Cycle Gas Cap	- G.P.P. @ 2000 BOPD	6,963,000	19.6	14,989,000
b)	Cycle Gas Cap	- G.P.P. @ 3000 BOPD	8,498,000	23.0	17,472,000
6.	Gas Cap Re-pressure	- G.P.P. @ 4000 BOPD	13,914,000	35.0	15,252,000
	Board Study **				
1.	Base Case - Gas Cap shut-in	- Prorated Oil Rates (1)*	14,800,000	37.0	21,000,000
2.	Gas @ 20.8 MMCFD	- Prorated Oil Rates (2)*	6,100,000	17.7	15,900,000
3.	Gas @ 14.0 MMCFD	- Prorated Oil Rates (3)*	8,800,000	23.6	18,300,000
4.	Gas @ 14.0 MMCFD	- G.P.P. (500 BOPD/Well Max.)	9,200,000	24.7	19,900,000
5.	Gas @ 9.5 MMCFD	- G.P.P. (500 BOPD/Well Max.)	10,900,000	28.4	19,300,000

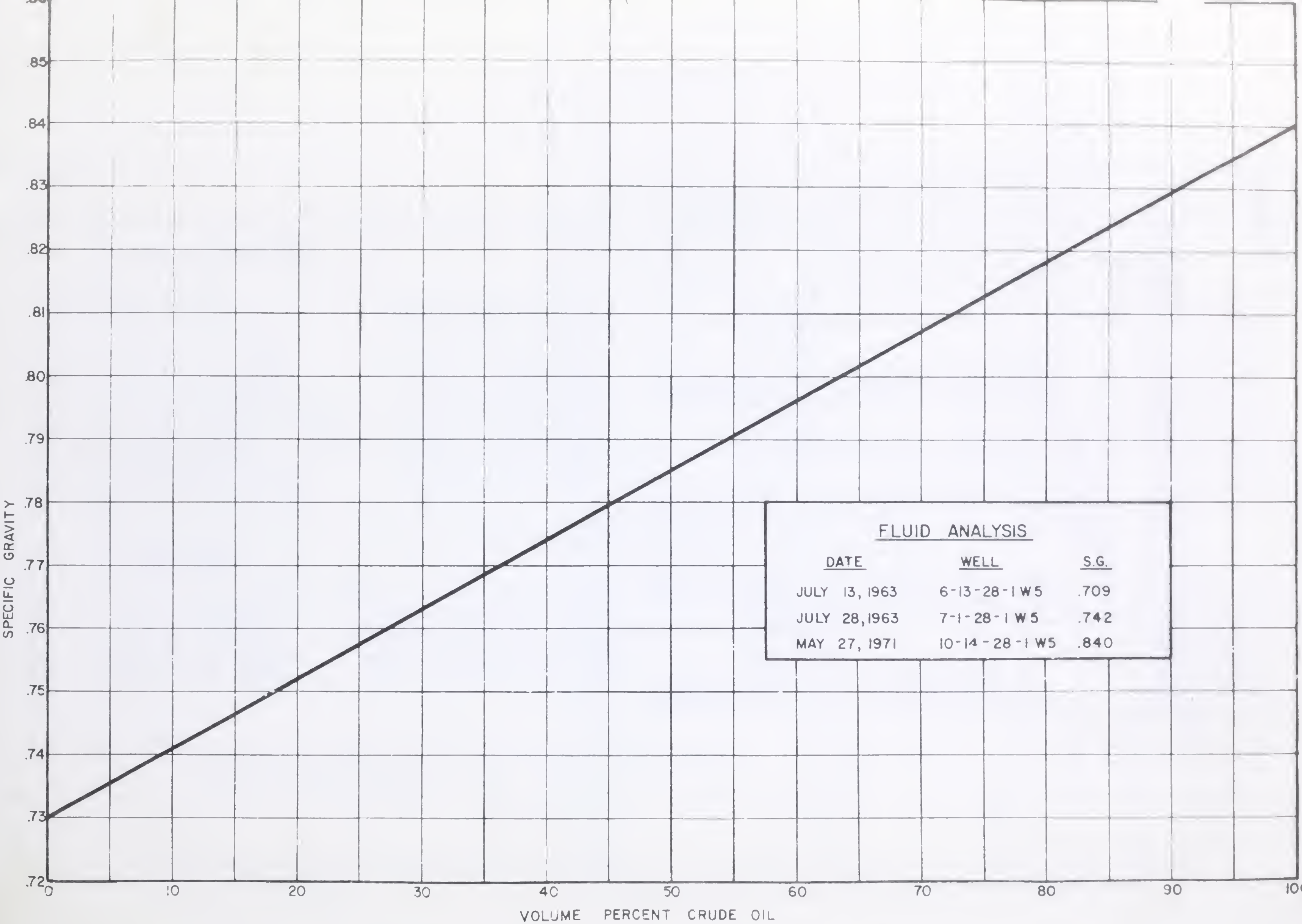
* Note:
Prorated Oil Rates based upon OOIP of 45,000,000 STB
and a recovery factor of: (1) 35%
(2) 15%
(3) 23%

** Board study recovery factors ignore the effects of coning and as a result are useful from a relative point of view only.

Attachment 3.

CROSSFIELD EAST ELKTON A AND D POOL PRODUCTION HISTORY
CONDENSATE YIELD CURVE VS MIXING CURVE COMPARISON

		Condensate yield curve (AMOCO DATA)			Mixing curve data (BOARD DATA)		
	Year	GAS (BCF)	CRUDE OIL (MSTB)	CONDENSATE (MSTB)	GAS (BCF)	CRUDE OIL (MSTB)	CONDENSATE (MSTB)
Elkton A	1965	3.08	93.0	103.9	3.04	53.5	143.4
	1966	3.60	106.2	117.2	3.55	59.3	164.1
	1967	3.80	82.3	117.3	3.75	60.0	139.6
	1968	3.21	83.4	82.2	3.13	99.2	66.4
	1969	5.94	72.2	153.9	5.86	104.4	121.7
	1970	7.44	168.9	163.0	7.33	173.3	208.6
	1971	6.96	129.9	106.8	6.94	125.1	111.6
Cumulative to Dec.31/71		34.03	735.9	844.3	33.60	674.8	955.4
Elkton D	1965	6.18	23.6	211.3	6.14	49.1	185.8
	1966	6.90	139.9	217.3	6.82	101.2	256.0
	1967	8.59	297.8	223.7	8.44	201.5	320.0
	1968	7.17	244.7	159.7	7.07	147.6	256.8
	1969	9.05	175.9	160.8	8.94	129.4	207.3
	1970	6.01	107.2	96.3	5.94	98.5	105.0
	1971	6.69	97.2	89.2	6.64	88.8	97.6
Cumulative to Dec.31/71		50.59	1086.3	1158.3	49.99	816.1	1428.5



CROSSFIELD EAST ELKTON A AND D POOLS

CONDENSATE – CRUDE OIL MIXING CURVE

ATTACHMENT #4

Attachment 5.

CROSSFIELD EAST ELKTON POOLS

DETERMINATION OF CRUDE OIL AND GAS IN PLACE

	AMOCO		BOARD		Board Decision
	Material Balance	Volumetric	Material Balance	Volumetric*	
Elkton A Pool					
Crude Oil (MMSTB)	18.000	larger	8.800	8.000	10.000
Gas Cap (BCF)	47.5	smaller	52.0	47.0	47.0
Elkton D Pool					
Crude Oil (MMSTB)	27.000	larger	13.500	12.300	15.000
Gas Cap (BCF)	66.5	smaller	71.6	66.0	66.0
Elkton E Pool					
Gas zone (BCF)	2.65	-	-	3.56	-
Elkton C Pool					
Gas zone (BCF)	15.0	-	-	32.0	-
Elkton B Pool					
Crude Oil (MMSTB)	-	-	-	1.180	-

* Proven reserves based on well data only.

ENERGY RESOURCES CONSERVATION BOARD

Decision 72-11
Application No. 6416

OIL RECOVERY ENHANCEMENT BY SOLVENT FLOOD AND WATER FLOOD SWAN HILLS SOUTH BEAVERHILL LAKE A AND B POOLS

THE APPLICATION AND HEARING

Amoco Canada Petroleum Company Ltd. applied for an amendment of Approval No. 1262 of a scheme in the Swan Hills South Beaverhill Lake A Pool and the Swan Hills South Beaverhill Lake B Pool;

(a) to convert a portion of the scheme from enhanced recovery of oil by water injection to a scheme for enhanced recovery of oil by solvent, gas and water injection, and

(b) to replace reservoir withdrawals in the solvent flood scheme on an annual basis.

The application was heard on August 2, 1972, by the Energy Resources Conservation Board, with G. W. Govier, P. Eng., V. Millard and D. R. Craig, P. Eng. sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Amoco Canada Petroleum Company Ltd.	J. D. Griffith, P. Eng. H. Gutek, P. Eng. P. Hay L. Horne W. Owens M. Sheffield J. Shelton	Amoco
Gulf Oil Canada Limited	T. E. Randall, P. Eng.	Gulf
Home Oil Company Limited	J. R. Sears, P. Eng.	Home

	Represented by	Abbreviation Used in Report
Imperial Oil Limited	W. B. Baker, P. Eng. R. H. Miller E. J. Muchowski D. E. Towson, P. Eng.	Imperial
Board Staff	J. A. Bray, P. Eng. D. N. Blades, P. Eng. C. C. Fortems, P. Eng.	

DECISION AND APPROVAL

The Board, by letter and Approval No. 1824, dated November 6, 1972, and attached as Appendices A and B hereto, approved the subject application under the terms and conditions specified in the approval. In the covering letter the Board stated that this decision would follow.

DEFINITION OF THE ISSUES INVOLVED

The Board believes that the application requires the consideration of the following matters:

(a) modelling the reservoir,

(b) miscibility,

(c) mobility control,

(d) residual saturations,

(e) solvent and gas slug sizing,

(f) ultimate recovery,

(g) gas and solvent supply, and

(h) monitoring and special considerations.

MODELLING THE RESERVOIR

(1) Views of Amoco

Amoco studied the depletion of the Swan Hills South Beaverhill Lake A Pool and the Swan Hills South Beaverhill Lake B Pool (hereinafter referred to as "the A and B Pools") by means of areal two-dimensional and vertical two-dimensional mathematical models.

The areal model completely encompassed the pools and provided Amoco with predictions of injection and production rates, pressure distribution, areal sweep and recovery, while the vertical models represented typical cross sections of the area to be solvent flooded. The results from these cross sectional models were used to modify the areal recoveries for vertical conformance.

In setting up the areal model, Amoco investigated a number of zonation techniques. These techniques included a Stiles type zonation, a geological zonation based on the depositional sequence, a statistical zonation based on permeability data, and a modified statistical zonation with a partly geological basis. Only the latter approach proved capable of representing the statistically based two layered system, while at the same time matching history of the water flood performance.

The applicant found a two layered representation to be statistically applicable to the greater portion of the pools, particularly in those central regions where lagoonal sediments are overlain by a streak of impermeable lime mud providing effective separation from the porous calcarenite. In the peripheral regions at the reef front, where deterioration of the tight lime mud is evident, communication between layers has been observed. To account for this communication, the upper layer (described as Layer 1 in the application) was extended to the perimeter of the pools. Only in the south-east corner of the pools, where localized geological changes occurred, did Amoco include the reef frontal material in the lower layer. Amoco also included the platform area on the east side of the reservoir in Layer 2. Generally, the applicant described Layer 1 as being continuously permeable throughout the vertical section in contrast with Layer 2 which was described as having many impermeable stringers disrupting the vertical continuity.

Amoco subsequently described a geologically defined two layer reservoir by a horizontal, rectangular 50 by 33 grid system having varied grid dimensions ranging from one-sixth to one-quarter of a mile. The reservoir properties of permeability, porosity and thickness for each grid block were determined by manual interpolation of core analysis data.

A number of assumptions were imposed on the areal model by Amoco. Following are those of particular importance concerning the flow of fluids through the reservoir:

(i) No vertical segregation of fluids within a layer.

(ii) No flow of fluids between Layer 1 and Layer 2.

(iii) Each layer permitted to produce and deplete independently.

(iv) Production from wells penetrating both layers was determined by the summation of the production predicted for the individual layers.

(v) The fluid displacing the oil in the miscible runs was assigned pseudo properties of viscosity and density of a solvent-water mixture, resulting in a mobility ratio of 0.24.

(vi) Continuous miscibility between the solvent and the oil.

(vii) A residual oil saturation of 5 per cent of the pore volume, subsequent to miscible displacement.

The vertical model studies provided Amoco with a conformance correction for its areal model predictions, since oil, solvent and water were treated as separate phases and vertical cross-flow was permitted. Hence, the reservoir phenomena of mobility control and gravity override could be studied in detail. In total, Amoco studied four different vertical cross sections of Layer 1 distributed throughout the solvent flood area and selected to represent a range of reservoir characteristics within the solvent flood area. Cross section A was composed primarily of lagoonal sediments, cross section B of reef edge material, whereas cross sections C and D were predominately of reef front facies with some overlying calcarenite. Layer 2, being highly stratified, was studied separately using a modified version of cross section A adjusted to allow no vertical continuity. The cross sections, each 4000 feet in length, contained two producing wells and a single injection well. The first producing well was 2600 feet from the injection well and the second, an infill well, was 4000 feet from the injection well.

Two different zonation techniques were considered by Amoco to facilitate the numerical description of the cross sections. Correlating porosity streaks between wells on the cross section proved to have no significant advantage over the simpler approach of dividing the gross interval of each well into twenty equal footage intervals. Offsetting wells with core analysis were inserted into the cross sections to provide additional control points and intermediate values of permeability, porosity and thickness between control points were determined by interpolation.

In situ vertical permeability tests were run in five well bores to determine the effective vertical permeability to be used in the 41 by 21 vertical grid systems employed to simulate the geological cross sections. Each test consisted of isolating two sets of perforations with a well bore packer and measuring the pressure response of the bottom set of perforations while known quantities of fluids were injected into or produced from the upper perforations. Amoco concluded, after analysis of the pressure responses, the vertical permeability obtained from a harmonic average of core analysis values was most representative of the in situ vertical permeability.

The more important assumptions assigned to the vertical models studied by Amoco are:

(i) Cross-flow of fluids between layers permitted.

(ii) The entire cross section open to flow into a well bore.

(iii) Oil, water and solvent treated as separate phases.

(iv) Miscibility between solvent and oil was assured at all times.

(v) A residual oil saturation of 5 per cent of the pore volume subsequent to miscible displacement.

(2) Views of the Board

On the assumption that a favourable mobility ratio can be maintained, the Board is in general agreement with Amoco's areal model studies and consequently did not conduct any areal models of its own.

The Board generally agrees with the applicant that a two layer representation provides an adequate definition of the reservoir. The Board has some concern however with Amoco's treatment of vertical continuity and the method used to model the vertical cross sections.

The Board agrees with Amoco that impermeable streaks cannot be correlated between wells and is therefore satisfied with the approach of dividing the gross interval of each well into equal footage intervals. On the basis that impermeable streaks cannot be correlated, the Board does not agree with Amoco's assumption that no vertical continuity existed within Layer 2. In addition, the Board does not consider the in situ vertical permeability tests run by Amoco to be conclusive proof that vertical flow characteristics will be dependent on a harmonic average permeability. The Board believes that it would be more realistic to use a geometric average vertical permeability.

To facilitate analysis of Amoco's work, the Board has studied the proposed depletion scheme in the A and B Pools with the aid of a two-dimensional vertical cross section model. The results from this model were used to verify the presently set water flood recovery factor, to determine the optimum injection distribution between the upper and lower layers, as defined by Amoco, and to determine the ultimate recovery factor for the proposed miscible flood scheme.

The vertical cross section chosen was considered typical for the solvent flood area having regard for capacity distribution, pore volume distribution and pool geology. The resulting cross section was described by a 20 by 10 vertical grid system having a uniform horizontal spacing of 1/20 of one mile and a vertical spacing obtained by dividing the porosity thickness of each well into ten equal footage intervals.

The reservoir rock properties for each grid block were determined by interpolation of core analysis data between the wells in the cross section.

Two simulations of water flooding the pool were run to determine the effect of different zonation definitions. The first simulation included a packer between the sixth and seventh layers in the injection well to obtain a more thorough sweep of the lower layers. The amount of water injected above and below the packer was proportioned on a hydrocarbon pore volume basis. The second simulation assumed no packer with injection into each of the ten intervals being proportional to its horizontal permeability.

The simulations showed that the use of the full interval completion in the injection well was a more reasonable approach than placing a packer in a well. Relatively large injection pressures experienced in the well bore suggested the packer placement scheme may be impractical.

The more important assumptions made in the vertical cross section solvent flood model runs were:

(i) Miscibility assured at all times.

(ii) Residual oil saturation after solvent flood is 5 per cent of the pore volume.

(iii) Vertical cross flow of fluids restricted only in those areas where the impermeable lime mud streak is present.

(iv) Oil, water and solvent treated as separate phases.

The Board concludes that Amoco realistically modelled Layer 1. However, in order to properly model the gross pay interval, Layer 2 should be included in the same cross section as Layer 1 since the two layers cannot be depleted independently. Further based on its geological sutdies, the Board believes that the area to be flooded by solvent is best represented by a Layer 2 that contains about 15 per cent of the total hydrocarbon pore volume and 3 per cent of the horizontal flow capacity. Thus a recovery from Layer 2 comparable to that predicted by Amoco would be achieved only if the flood was controlled to permit an equal rate of advance in each layer. The Board believes that a dual completion program which would be required for such a scheme is not practical and concludes that the recovery predicted by Amoco for Layer 2 is optimistic.

In summary, the Board believes that its cross sectional model of the reservoir, incorporating the full pay interval in a single cross section, is more realistic than the applicant's representation of the reservoir as two separately modelled layers.

MISCIBILITY

Solvent-Oil Miscibility

(1) Views of Amoco

The proposed solvent is a multi-component system consisting of nitrogen, carbon dioxide and a range of hydrocarbons from methane to pentanes-plus. Amoco described the solvent as a pseudo two component system defined in terms of methane (including carbon dioxide and nitrogen) and ethane-plus.

Amoco calculated miscibility conditions for the Swan Hills South crude and solvent using Benham's(1) correlation over a range of pressures and a temperature of 227 degrees Fahrenheit (°F). It indicated that at the proposed operating pressure of 2350 pounds per square inch gauge (psig) a solvent containing 50.3 mole per cent ethane-plus would be miscible with the reservoir crude. In order to verify the results of the Benham correlation, Amoco conducted a series of laboratory displacement tests using a recombined reservoir fluid sample and a number of solvents of various composition. The results of these tests indicated that the enrichment requirement for solvent-oil miscibility is similar to that calculated by Benham at equivalent pressures. Although no laboratory tests were run at the proposed operating pressure, Amoco stated that the tests that were run adequately bracketed the 2350 psig pressure so that an interpolation could be made with a high degree of confidence.

Amoco stated that a safety factor was not included in the proposed solvent composition but contended that two factors indirectly contribute to ensuring solvent-oil miscibility. Firstly, the pressure for a substantial distance around the injection well would be much higher than the 2350 psig pressure that was used to establish a miscible composition and secondly, the carbon dioxide possibly should have been included with the intermediates as an enriching agent instead of with the methane. However, in reply to questioning by the Board, Amoco stated that it would be amenable to including a small safety factor in ethane-plus enrichment subject to additional review on the size of the safety factor.

(2) Views of the Board

The Board considers that the experiments conducted by Amoco are satisfactory for determining the conditions of miscibility and support the results of Benham's correlation. The Board accepts Amoco's contention that a solvent containing 50.3 mole per cent ethane-plus

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(1) Benham, A.L., Dowden, W.E., and Kunzman, W.J.; "Miscible Fluid Displacement - Prediction of Miscibility", Trans. AIME (1960) Vol. 219, 229.

will satisfy the miscibility requirements and it agrees that this is substantiated by the results of the laboratory tests.

The Board does not agree with Amoco that the carbon dioxide should be included with the intermediates in miscibility calculations. However, the miscibility conditions would not change since any effect would have been included in the results of the laboratory displacement tests. The Board agrees that if the reservoir pressure were maintained above the proposed operating pressure the solvent composition would contain a certain safety factor in the ethane-plus content. However, the Board believes that an additional allowance should be made to account for variations in actual reservoir conditions from the theoretical laboratory tests and for any experimental inaccuracies in the sight-cell determination of miscibility conditions. The Board believes that a nominal 3 mole per cent safety factor should be included. Therefore, for a flood pressure of 2350 psig, the solvent should contain not less than 53 mole per cent ethane-plus. The Board would be prepared to reconsider this safety factor should additional supporting data be provided.

Solvent-Gas Miscibility

(1) Views of Amoco

Amoco calculated the phase behavior for a system of varying solvent composition over a range of pressures and temperatures. The phase diagram was calculated by the Benedict-Webb-Rubin[1] equation of state and it indicated that all mixtures of solvent and driving gas would be in the singel phase region at a reservoir temperature of 227°F.

(2) Views of the Board

The Board agrees with Amoco that solvent-gas miscibility will be ensured for all mixtures of solvent and driving gas at reservoir conditions.

MOBILITY CONTROL

(1) Views of Amoco

Amoco indicated in its application that alternate injection of solvent and water followed by scavenging gas and water would remedy the low volumetric sweep efficiencies normally associated with the inherently unfavourable mobility ratio of solvent floods. Investigations

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(1) Yarborough, L. and Smith, L.: "Solvent and Driving Gas Compositions for Miscible Slug Displacement", Society of Petroleum Engineers Journal, Vol. 10, P. 298-310 (1970).

showed that where the hydrocarbon-water phases advance together displacing oil, a favourable mobility ratio resulted with sweep efficiencies comparable to those observed in water flood operations. Mobility control was attributed to the reduced relative permeability characteristics of multiphase flow and the viscosity differential between water and solvent.

As a first step in simulating the mobility control dictated by multiphase flow, Amoco determined in the laboratory the relative permeability data for the oil-water and gas-water systems. These relations adequately described the immiscible displacement mechanism associated with the two phase systems. To extend the relative permeability concept to the proposed scheme, which entails three phase flow and miscible displacment, Amoco developed pseudo relative permeability curves. In addition to describing the flow characteristics of the two miscible components making up the hydrocarbon permeability, these functions controlled the mixing zone length and established the flushing efficiency. The lowest solvent saturation, representing the commencement of solvent flow, dictated that the mixture of solvent and oil would approach one to two block lengths, a distance comparable to that calculated independently from the miscible molecular dispersion coefficients. The upper end point, representing the cessation of oil flow, was established by residual oil saturations measured in the laboratory. Verification of such curves through laboratory experimentation was not feasible, for in contrast to the field case, the mixed zone length of miscible type displacement tests is often equivalent to the entire length of the laboratory test system.

Amoco, in reply to questioning, indicated that the fluid properties of viscosity and density were handled differently in the vertical cross sectional studies as compared to the horizontal areal studies. In the former case oil, solvent and water were treated as separate phases having properties of the respective pure components. This is a somewhat conservative approach, as it ignores the tendency for the solvent to disperse in the oil thus yielding effective viscosity and density differences less extreme than those of the pure components. Amoco's areal simulation assured mobility control by treating the solvent and water as a single phase with viscosity and density properties of the combined mixture.

In addition to the sensitivity analysis conducted to establish the proper pseudo permeability curves, Amoco used the vertical cross section model to experiment with the relative effects of simultaneous versus alternate fluid injection on mobility control. The alternate injection of solvent and water was observed to mix and approach a simultaneous flow regime almost immediately upon entering the reservoir. Thus, Amoco concluded that simultaneous injection adequately represented the field condition of alternating solvent-water injection and applied the conclusion throughout the study.

In analysing the results from the model studies, Amoco observed that the water and solvent were staying together for a greater part of the prediction period. Although some front running of solvent was observed in the upper two layers of the cross sectional studies, this did not depict any serious deterioration of the displacing mechanism. Amoco indicated that Caudle and Dyes[(1)] confirmed this observation by measuring typical miscible displacement oil recoveries despite the presence of a highly mobile miscible gas zone in advance of the mobility controlled gas-water zone. On the basis of these findings, Amoco concluded that the alternate injection of solvent and water would maintain mobility control.

In its application, Amoco indicated that a critical factor in the design of the proposed scheme would be the injection schedule. Each injection well would receive approximately one million barrels of water prior to the alternate injection of solvent and water. This pre-flush with water should ensure mobility control from inception of the scheme.

Amoco presented a procedure for calculating the optimum solvent-water injection ratio. The proper ratio ensures that the solvent and water advance through the reservoir at the same rate. If too little water were injected, the scheme would revert to a gas driven solvent flood with an unfavourable mobility ratio, whereas too much water would require the handling of an excess of produced water. Utilizing this approach Amoco estimated an optimum ratio of 1.25 for both the alternate injection of solvent-water and gas-water. The correction for the viscosity difference between solvent and gas was considered insignificant.

When asked about successful field cases where mobility control of a solvent flood has been achieved through alternate solvent-water injection, Amoco cited the schemes in the Ante Creek Field of Alberta and the Fairway Field of Texas. The Ante Creek scheme has experienced limited breakthrough but no earlier than was predicted. The breakthrough to date is not attributable to a loss of mobility control, but rather can be explained by the presences of a free gas phase at the commencement of the scheme and a four foot, high permeability capacity stringer located at the bottom of one of the injection wells.

In the Fairway Field case, it is Amoco's understanding that the scheme could have been improved if a miscible slug had been injected that would assure miscibility from inception and if each gas-water injection cycle were confined to five per cent of the pore volume. Generally, however, the operator at Fairway is said to be satisfied with the flood and the mobility control suggested by recoveries to date.

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(1) Caudle, B.H. and Dyes, A.B.: "Improved Miscible Displacement by Gas-Water Injection", Trans. AIME (1958), Vol. 213, 281.

(2) Views of the Board

The Board has considered the mathematical techniques used by Amoco to study the proposed scheme, has appraised the results and conclusions, and is generally in agreement that the model demonstrates the alternate injection of solvent and water will achieve and maintain mobility control. The mathematical simulation of typical vertical cross sections appears to have resolved the theoretical questions respecting the detrimental effects of reservoir heterogeneity and gravity override.

In the opinion of the Board, Amoco's handling of Layer 1, as discussed under the heading "modelling the reservoir", should adequately reflect the influence of reservoir heterogeneity on mobility control. Similarly, the Board is satisfied that Amoco's treatment of oil, solvent and water as independent phases in the vertical model studies will readily permit the fluids to segregate where the gravity-viscous forces favor such segregation.

Two additional factors known to influence mobility control but not considered by Amoco in its modelling are molecular dispersion and viscous fingering. In reviewing the literature, the Board notes that past successes at simulating molecular dispersion associated with solvent floods have been confined to the design and placement of the solvent bank. To attempt to predict performance of a field size problem would be impractical because of mathematical and computer storage limitations. Recently Todd and Longstaff[1] demonstrated that full scale solvent flooding projects can be adequately represented by means of an empirical model. Pseudo-relative permeability curves are employed which permit each of the miscible components to flow at a fraction of the non-wetting phase relative permeability equal to its volume fraction in that phase. Viscosity and density formulations are also presented which attempt to reflect the tendency for solvent to disperse in the oil. The authors' summary indicates that the approach is only a computational expedient not intended to simulate the actual physical dispersion.

Amoco's approach is similar to that of Todd and Longstaff with the exception that the pseudo-relative permeability curves were modified in an attempt to simulate the analytically calculated physical dispersion. This was accomplished in the vertical cross sectional models by permitting the solvent to flow whenever the solvent saturation exceeded 90 per cent of the hydrocarbon saturation.

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(1) Todd, M.R. and Longstaff, W.J.: "The Development Testing and Application of a Numerical Simulator for Predicting Miscible Flood Performance", Journal of Petroleum Technology (July 1972) 874-882.

The Board notes that the standard finite difference techniques employed in mathematical reservoir simulators unfortunately do not provide a practical means for analysing the effect of viscous fingering. Adequate definition of the unstable frontal advance associated with viscous fingering would necessitate prohibitive computer storage requirements, even for a very simple system. Therefore, for any reasonable grid system, mixing cell affects dampen the flow instabilities to the extent that a somewhat optimistic approximation of fingering is simulated.

In view of the empirical approach to mathematical simulation of a solvent flood operation, the Board decided to perform a number of sensitivity runs to evaluate the effect of pseudo-relative permeability curves on mobility control. A cross section, comparable to Amoco's cross section A, but including Layer 2, was simulated using NCØMP[(1)] modified to handle the miscible displacement mechanism. After some experimentation straight line relative permeability curves, which provided a reasonable oil-solvent mixing zone length, had end points of 50 and 89 per cent of the hydrocarbon saturation. Saturation profiles predictions resulting from using these curves portrayed limited gravity override of approximately two grid blocks until after breakthrough into the first well in the cross section. Thereafter the solvent finger progressed rapidly along the top of the reservoir while only limited advance was observed over the remainder of the cross section. The lower four-tenths of the cross section, making up the equivalent of 80 per cent of the Board's interpreted Layer 2, accepted little or no solvent. Consequently, only water flood recovery was considered applicable to this portion of the pore volume. On the basis of this observation, the Board concludes the vertical conformance cannot be adequately evaluated unless Layer 1 and Layer 2 are considered in the same cross section.

In an attempt to evaluate the worst possible override case, a second prediction was performed with the end points of the vertical relative permeability curve altered to 0 and 89 per cent of the hydrocarbon saturation. In this case the override was only slightly more severe until breakthrough into the first well. Thereafter the solvent quickly flooded through the upper layer reaching the second well in about half the time required to achieve breakthrough at the first well. The two sets of pseudo-relative permeability curves yielded results approximating those predicted by Amoco.

The simultaneous injection of solvent and water used by Amoco throughout its simulation runs in place of alternate injection, was investigated by the Board, as this assumption was suspected to have a significant influence on the retention of mobility control. The Board's findings agreed with those of Amoco.

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(1) NCØMP, a three-dimensional, N-component model developed by Scientific Software Corporation of Denver, Colorado.

Neither Amoco or the Board were able to analyse in their simulation studies the ability of gas to displace solvent. The simulators are capable of considering only a three phase system, whereas the proposed scheme will involve the simultaneous flow of four distinct phases (ie., oil, solvent, water and gas). Consequently, a 40 per cent hydrocarbon pore volume miscible slug was used to represent the proposed 10 per cent solvent slug and 30 per cent gas slug. If the three phase limitation had not existed, and the fluid displaying override in the cross sections were predominately solvent, miscible displacement would be restricted to those layers contacted by solvent. Where the displacing gas contacts the oil bank directly, the displacement would revert to an immiscible gas injection scheme. Amoco's adjustments for the override and limited bank size were found to be difficult to quantify, and may not have been adequately recognized in the recovery calculation.

Because of the three phase limitation discussed above, the mobility control between the gas and solvent phases has not been investigated. The viscosity and density differences between gas and solvent are less than those between oil and solvent. The Board therefore concludes that viscous fingering and gravity override will be less important where gas is displacing solvent. Whether gas will by-pass significant volumes of solvent is a related matter not investigated. However the reservoir simulator and displacement tests have demonstrated that the solvent will displace the oil in the presence of a high water saturation. Similarly, the gas in the presence of a water phase should displace the solvent due to the control of viscous forces. Therefore the Board believes that mobility control would be maintained between gas and solvent and those areas contacted by the solvent should subsequently be contacted by gas.

Amoco's proposal to pre-inject a water slug of 1,000,000 barrels into each injection well prior to commencing alternate injection has been interpreted by the Board as one of the more important modifications to previous alternate injection schemes. The Board concurs with this modification.

The Board has considered the mathematical technique used by Amoco to claculate the optimum solvent to water injection ratio, and is generally in agreement that a ratio of 1.25 should theoretically ensure that the solvent and water advance at the same rate.

In regard to field cases utilizing horizontal displacement of a solvent bank, the historical record does not present a very encouraging picture. The schemes of this type, undertaken in Alberta, that now have an extensive history are all in the Pembina Cardium Pool, and the very different geologic and permeability features of this reservoir compared to the subject reservoir must of course be taken into account. Further, these early schemes used solvent banks of from 1 to 3 per cent of pore volume and the scheme with the most history did not intersperse slugs of water throughout the solvent bank. The least mature of the Pembina schemes do not have enough history to provide for a conclusive analysis of their performance.

The Ante Creek Beaverhill Lake Pool in Northern Alberta has been cited as a promising example of an operating horizontal bank displacement, but the Board notes that its history is still quite short and that subject to interpretation, one of two patterns has shown increasing gas-oil ratios. The Fairway Scheme in Texas was also cited by the applicant, but the Board notes that early breakthrough was observed, the scheme history is still limited and the operator has indicated that there are several significant modifications that it would incorporate into a future, similar scheme.

The Board is not aware of a single mature, proven successful application of the displacement mechanism proposed for the A and B Pools and notes that the schemes with production history amply demonstrate the severity of the mobility-heterogeneity problems faced by the inherently unstable horizontal solvent bank displacement.

At this date it is impossible to quantify the effect that unfavourable mobility in the presence of heterogeneity at field dimensions will have on solvent bank size. It would appear that the solvent bank size and the water slugs that comprise the appropriate design for the specific heterogeneities of the A and B Pools cannot be engineered more precisely without some actual performance data. Nevertheless, the Board believes that the applicant has recognized the instability problem and has made reasonable allowances for it in the size of the solvent bank proposed, by the pre-injection of a water slug before injection of solvent, and by the use of subsequent interspersed slugs of water in the solvent and gas banks.

RESIDUAL SATURATIONS

(1) Views of Amoco

Since the mobility ratio calculated for the proposed solvent flood scheme is essentially the same as that calculated for a water flood scheme in this pool, the increased recovery under the solvent flood will result from a decrease in the residual oil saturation in that part of the reservoir in which the oil is miscibly displaced. Amoco stated that the water flood end point residual oil saturation, based on the water-oil relative permeability curve from a steady state test on a restored state core adjusted to the reservoir connate water saturation, was 34 per cent pore volume.

Steady state displacement tests performed on two restored state core samples from the Swan Hills South Beaverhill Lake formation were used to determine relative permeability of water displacing gas. The average of the two curves, adjusted to the reservoir connate water saturation, was used in the study. The tests resulted in a residual gas saturation of approximately 40 per cent pore volume.

Amoco submitted that the residual oil saturation associated with the miscible displacement of the reservoir oil by solvent would be 5 per cent of the pore volume. A value of 10 per cent, the residual saturation evident prior to completion of additional displacement tests, was used in the reservoir model study. The results of the study were subsequently adjusted to reflect a 5 per cent pore volume residual oil saturation. The 5 per cent residual oil saturation was based on nine miscible displacement tests conducted on seven restored state Swan Hills Beaverhill Lake formation cores which were saturated with connate water and crude oil. Approximately 25 pore volumes of propane were injected through the core samples and the residual oil saturations were determined by both material balance and extraction techniques. Seven of the displacement tests were conducted at a frontal advance rate of six feet per day whereas the other two tests were performed at a rate of one foot per day. The arithmetic average residual oil saturation of the higher rate tests was 8.3 per cent pore volume and the average from the lower rate tests was 4.4 per cent pore volume. Amoco stated that there was some evidence of the residual oil saturations being sensitive to the test rate and that none of the test rates approached the anticipated reservoir contact times. Therefore Amoco contended that the residual oil saturation may be somewhat lower than that indicated by the displacement tests. Amoco also pointed out, however, that the variations in the residual oil saturation in the cores could be the result of measurement techniques or heterogeneities in the core. The applicant submitted data from 24 miscible displacement tests conducted on native state carbonate cores from the San Andres formation in the Levelland Field in Texas to illustrate that the residual oil saturation is not altered by pre-injection and concurrent injection of water with the miscible displacing fluid or by the presence of mobile water. These tests resulted in an average residual oil saturation of less than 5 per cent pore volume.

Amoco did not conduct laboratory tests to determine the magnitude of the residual solvent saturation which would remain in the reservoir as the result of dry gas miscible displacement of the solvent slug. In estimating this residual saturation the applicant referred to the residual oil saturations indicated by the solvent-oil miscible displacement tests, and stated that the 5 per cent pore volume value indicated by these tests would represent the maximum residual solvent saturation. Since it was not considered probable that the residual oil saturation would be displaced by a residual solvent saturation a value of 2 per cent pore volume was estimated to be representative. Amoco stated that if a residual hydrocarbon saturation remained after a miscible oil-solvent-gas displacement, the residual saturation would have a composition varying between the three phases. No attempt was made to account for the combination residual oil and solvent saturation in Amoco's mathematical reservoir model since this involves a dispersion and diffusion mechanism which could not be adequately modelled simultaneously with multi-phase displacement. The pseudo-relative permeability curve used in the model to describe solvent flow defined solvent relative permeability as occurring when the solvent saturations were between 90 and 98 per cent of the hydrocarbon saturation. In answer to questioning the applicant agreed that a residual solvent saturation of 2 per cent pore volume would have the effect of reducing the solvent slug size from 10 per cent hydrocarbon pore volume (HCPV) to 8 per cent HCPV.

(2) Views of Imperial

Imperial submitted that the applicant may not have accurately estimated the amount of incremental production which would be realized from a solvent flood compared to a water flood due to the magnitude of the water flood residual oil saturation used in the reservoir study. Imperial based its intervention on a single well tracer test conducted in the Judy Creek Beaverhill Lake A Pool which indicated a water flood residual oil saturation of approximately 12 per cent pore volume. Imperial contended that the low residual saturation could indicate a high water flood displacement efficiency and low sweep efficiency such that a lower incremental recovery between the conventional water flood and Amoco's proposed solvent flood is suggested which could effect the economic advantage of the solvent flood.

Imperial outlined the method of evaluating residual oil saturations in a water flooded portion of the reservoir through the injection of a tracer fluid of ethyl acetate into a well followed by the monitoring of the subsequent production of ethyl acetate and that portion of the ethyl acetate which hydrolyzes in the formation to form ethanol. A paper by Dalton and others(1) was referenced for details of the procedure and analysis. As a measure of the validity of the test in carbonate rock Imperial measured the residual oil saturation in a weathered Judy Creek Beaverhill Lake formation core sample and compared the results of an ethyl tracer test conducted on the same core. The results of the tracer test indicated a residual oil saturation of 29 per cent pore volume compared with a measured residual oil saturation of 28.9 per cent pore volume. Imperial pointed out that the absolute values of these residual saturations are not significant since this was not the intent of the test.

Imperial was questioned regarding the effect that residual oil swelling, rate of ethyl acetate reaction, displacement velocity and wettability changes would have on the test results. It was acknowledged that many of these effects were unknown but that they would generally be of minor significance due to the low concentrations of ethyl acetate. When questioned as to the appropriate curve fit applied to the data points from the test, the intervener stated that the fit was most critical in the area of the highest measured concentrations of the tracer.

Under examination Imperial stated that the results of the single well tracer test have provided an evaluation of residual oil saturation in a large section of a water flooded reservoir and have indicated that the standard methods of determining residual oil saturations from core tests may not be representative of the reservoir.

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(1) Dalton, R.E., Deans, H.A., Shallenberger, L.K., and Tomich, J.F.: "Single Well Tracer Method to Measure Residual Oil Saturations", S.P.E. 3792. Improved Recovery Symposium, Tulsa, Oklahoma, April 1972.

When questioned on the acceptance of this technique by industry, Imperial stated that six single well tracer tests have been conducted to date and additional tests will be conducted to evaluate the process and compare it with other techniques for determining residual oil saturations.

(3) Views of the Board

In determining residual oil saturations of water flooded reservoirs the Board generally accepts the values obtained from displacement tests performed on representative core material. Although the Board notes that there is a wide range of residual oil saturation values obtained from water flood displacement tests in core samples from the Swan Hills and Swan Hills South Beaverhill Lake formations, it believes that the 34 per cent pore volume value used by Amoco in its reservoir model is a representative average of the data.

The Board has considered the evidence contained in Imperial's intervention and finds that the field test data are of considerable interest. However, the Board believes that the limited use of the single well testing procedure to date, coupled with the undefined effect of several factors on the analysis technique, does not result in sufficiently conclusive data to provide for a departure from the presently accepted method of evaluating residual oil saturation.

The Board accepts the results of the miscible displacement tests conducted on Swan Hills and Levelland Field core samples as the basis for determining the pore scale residual oil saturation after miscible displacement. It is noted that the residual oil saturation appears to be rate sensitive and, having regard for the anticipated length of contact time in the reservoir, the value of 5 per cent pore volume used in the applicant's model would be appropriate. The applicant's core displacement tests, conducted to demonstrate that the residual oil saturation is not dependent upon the amount of mobile water present in the reservoir, are considered to be reasonably reliable.

The Board notes that Amoco's residual gas saturation was obtained from water displacement of only two core tests but feels that the value is satisfactory on the basis of the residual oil saturations obtained by water displacement in core samples from Beaverhill Lake pools.

The applicant did not conduct any displacement tests to determine the magnitude of the residual solvent saturation subsequent to dry gas and water displacement. However, the applicant stated that the residual solvent saturation would be, at a maximum, equal to the residual oil saturation and that in the field case this would not be probable due to the fact that this would require all of the oil to be displaced by solvent. On the basis that mobility control will be maintained during the displacement of the solvent by alternate slugs of dry gas and water, the Board is prepared to agree with Amoco's conclusion. The value of 2 per cent pore volume estimated by the applicant would appear to be realistic since it is unlikely that all of the residual oil would be displaced by the solvent.

SOLVENT AND GAS SLUG SIZING

(1) Views of Amoco

Amoco based the optimum slug size on economic considerations and sensitivity work carried out on its three phase vertical model. By varying the slug size, Amoco determined that there was little additional miscible sweep for slug sizes in excess of 40 per cent HCPV. Amoco stated that the recoveries associated with the computer runs were reduced to account for possible immiscible displacement by dry gas. Having regard for the reduced recoveries and their respective economics, it concluded that a 40 per cent slug, inclusive of solvent and displacing gas, appeared to be reasonably close to the optimum. Amoco conducted further studies to estimate the size of the solvent bank which would maintain miscibility and provide the recoveries calculated in the miscible model runs. Subsequently, it proposed that the 40 per cent HCPV slug be made up of a 10 per cent HCPV solvent bank displaced by 30 per cent HCPV of dry gas.

Amoco's calculation of a solvent slug size of 10 per cent HCPV was based on an empirical relationship which correlates longitudinal mixing as a function of viscosity difference, viscosity ratio and distance travelled[1]. The correlation is based on contact miscibility and assumes a mixing zone length independent of the flow velocity. Amoco indicated that this is qualitatively supported by published experimental and theoretical work which concludes that over a range of characteristic field velocities the mixing zone length remains essentially constant.

Amoco indicated that the predominant mechanism for gas-solvent and solvent-oil mixing is convection rather than molecular diffusion forces and, as a result, the mixing zone length measured at a fixed distance would remain fairly constant over the range of characteristic field velocities and would be only a function of the distance travelled. In reply to questioning, Amoco stated that convective mixing contributes more in the direction of flow than does molecular diffusion but it agreed that diffusion effects would cause some mixing. Amoco agreed that the diffusion and convection theory given by Perkins[2] could be applied to this system if the correct parameters were available to put into it. Amoco suggested that when the Perkins theory is applied to the Swan Hills South reservoir the solvent-gas mixing zone would be several times larger than that indicated by the empirical correlation. Amoco acknowledged that its correlation could result in a solvent-gas mixing zone length which would be shorter than that expected in the reservoir.

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(1) Hall, H.N. and Geffen, T.M.: "A Laboratory Study of Solvent Flooding", Trans. AIME (1957), Vol. 210, 48.

(2) Perkins, K.T. and Johnson, O.C.: "A Review of Diffusion and Dispersion in Porous Media", Society of Petroleum Engineers Journal (March 1963), Vol. 3, No. 1.

Amoco used a 5-spot two layer reservoir model in conjunction with the above correlation to study pattern effects and calculate areal sweep to loss of miscibility for a given solvent slug size. Permeability variations of 5, 10 and 20 to 1 were assigned to the two layer 5-spot systems to account for effects of permeability stratification upon solvent requirements. This study did not include residual solvent saturations but it did account for an increase in water saturation above connate water saturation such that the water will occupy some of the mixing zone volume and thereby reduce the solvent requirements. The model also assumed that the hydrocarbon mixed zone volume was 100 per cent solvent whereas theoretically it is only 50 per cent. Amoco concluded that a 5 per cent HCPV solvent bank would be adequate to achieve the recoveries predicted in the miscible model runs for a 20 to 1 permeability variation between the layers. Amoco increased this to 10 per cent HCPV to allow for bank degradation due to detrimental effects such as reservoir heterogeneities, viscous fingering, gravity override, solvent trapped as residual, transverse diffusion and capacitance. Since the original 5 per cent slug had a safety factor of 100 per cent by considering the hydrocarbon mixing zone volume to be all solvent, Amoco claimed that the safety factor which has been incorporated in the solvent bank size is actually 400 per cent.

Amoco was not able to quantitatively assess the end result of all the possible detrimental effects on solvent bank requirements but it indicated that the safety factor included in the design was more than adequate to compensate for any possible bank degradation. Amoco stated that additional solvent mixing due to capacitance effects would have a minor influence on the solvent bank but agreed that diffusion of the oil into the bank behind the flood front could result in a solvent composition too low in hydrocarbon intermediates concentration for continued miscibility. However, it contended that the long contact times expected in the reservoir, 2 to 3 years, should minimize this effect. Amoco recognized that additional dilution of the bank could occur due to transverse diffusion and that in certain localized situations the bank could be insufficient. Therefore, as discussed previously, it reduced the miscible recovery by a judgement factor which included the effect of transverse diffusion.

Amoco conducted three miscible displacement tests on a Berea sandstone system 20 feet in length to study the effect of the water phase on mixing zone lengths. The displacements were run at rates of about 5 to 10 feet per day with oil to solvent viscosity ratios in the order of 40. The tests included both water wet and oil wet systems with a water saturation in the solvent zone ranging from 0 to 45 per cent. The measured mixing zone lengths of the displaced and displacing fluids were approximately the same for all tests and Amoco suggested that since the Swan Hills South reservoir possibly is oil wet, an increase in water saturation above the connate would have no effect on mixing zone lengths and solvent requirements.

(2) Views of Home

Home stated that due to reservoir heterogeneities and the effect of capacitance the solvent slug could be substantially diluted. In this regard, Home contended that the proper slug size may be considerably larger than the 10 per cent HCPV slug proposed by Amoco. Home also expressed some doubt as to the adequacy of using a correlation developed for contact miscibility to simulate a system that is conditionally miscible. Home stated that its conclusions are based only on an intuitive assessment of the scheme and it could offer no substantive evidence.

(3) Views of the Board

The Board is prepared to accept Amoco's contention that a 40 per cent HCPV slug comprised of 10 per cent solvent and 30 per cent displacing gas is reasonably close to the optimum. The Board in its assessment of the solvent slug size considered the miscible sweep indicated in the Board's model runs and concluded, as did Amoco, that there was little additional incremental miscible displacement with the injection of a HCPV slug of solvent and gas greater than 40 per cent.

The Board is of the opinion that there is no satisfactory method to represent accurately the areal and vertical distribution of a finite solvent bank or the degree of bank degradation, and believes that the possible detrimental effects discussed previously could seriously reduce the effective bank size. However, the Board attempted to study the effect of reservoir heterogeneities on bank design and concluded that the hydrocarbon slug proposed by Amoco would be appropriate.

The Board is of the opinion that the empirical correlation used by Amoco to describe the degree of mixing between the gas, solvent and oil phases is not representative of the actual system and is particularly not applicable to the gas-solvent interface. The Board believes that both molecular diffusion and convective mixing will contribute to the overall dispersion coefficient and accordingly assumes that the equation of the type given by Perkins more accurately describes the dispersion process. The Board, based on its interpretation of the appropriate parameters to be used in the Perkins equation for the Swan Hills South reservoir, calculates that the mixing zone length including both the leading and trailing edges of the solvent bank is approximately twice that calculated by Amoco's empirical correlation. However, since Amoco has in effect doubled the mixing zone length by considering the total hydrocarbon mixing zone volume to be solvent, the solvent requirements calculated by both methods would be similar. Therefore, the Board concurs that for a two layer system having a permeability variation of 20 to 1 between layers a solvent bank of 5 per cent HCPV would be adequate to maintain miscibility and give recoveries similar to those indicated by Amoco's vertical model. However, the safety factor included in the design would be 100 per cent rather than the 400 per cent calculated by the applicant. Since the predicted miscible sweep is only about 50 per cent of the reservoir, the proposed solvent bank would represent 20 per cent of the HCPV miscibly displaced.

The Board believes that the laboratory displacement tests run on the Berea sandstone system do not offer conclusive evidence of the effect the water phase will have on the mixing zone lengths of the gas-solvent and solvent-oil interfaces. However, the Board is of the opinion that any increase in solvent requirements resulting from inaccuracies in the mixing zone length determination would be negligible when compared to the effect of the reservoir heterogeneities.

The Board recognizes that the Amoco design method is for a simplified case and that any detrimental effects in the reservour must be accounted for by an appropriate safety factor. In spite of the many unknowns and the inherent uncertainties in sizing the solvent bank, the Board is satisfied that the proposed solvent volume should be sufficient to maintain miscibility over that portion of the pool contacted by solvent. The Board believes that if mobility control will actually be obtained on the field scale, the reservoir heterogeneities will not seriously disrupt the competence of the bank. Nevertheless it appears that the scheme performance should be reviewed not more than three years after the commencement of solvent injection to determine the overall efficacy of the scheme and the effect of reservoir heterogeneities on solvent bank design.

ULTIMATE RECOVERY

(1) Views of Amoco

The applicant's volumetric determination of the original oil in place within the area of the proposed solvent flood was 580,100 MSTB. The pool total original oil in place of 889,000 MSTB was computed from the areal model.

A water flood prediction using vertical cross sectional models indicated that all of the reservoir would be contacted by water and therefore no sweep adjustment would have to be made to the results obtained from the areal model prediction. The areal model prediction was conducted on each of two layers with both a regular nine spot injection pattern and the injection pattern proposed for the solvent flood scheme. The latter pattern is a combination line drive, nine spot pattern as illustrated by Figure 1. Amoco submitted that recoveries predicted from each pattern studied were essentially the same at the year 2013 and therefore concluded that the proposed solvent flood pattern was the best since it had more producers per injector and would realize the maximum water flood recovery. An ultimate water flood recovery factor of 45.9 per cent corresponding to an oil in place of 889,000 MSTB was calculated for the pool at a water-oil ratio of approximately 6 to 1. This recovery factor for the proposed solvent flood area of the pool was calculated to be 46.7 per cent of 320,290 MSTB of original oil in place for Layer 1 and 41.3 per cent of 259,859 MSTB of original oil in place for Layer 2.

Amoco evaluated the solvent flood recovery factor by running the model on six different vertical cross sectional models and two areal models, one for each layer. Recovery data obtained from the vertical and areal models were combined to calculate the ultimate recovery factor for the proposed solvent flood.

Amoco submitted that the areal model results indicated recoveries of 86.2 per cent and 73.5 per cent in Layers 1 and 2 respectively of the proposed solvent flood area, assuming a residual oil saturation of 10 per cent pore volume. These values were increased by the applicant to 92.2 per cent and 78.8 per cent to reflect a residual oil saturation of five per cent pore volume. The injection pattern used in the areal model study was that proposed for the solvent scheme and did not assume any infill drilling of producing wells.

The miscible recoveries determined from the six vertical cross sectional model predictions were adjusted to account for those areas which would have been displaced by dry gas rather than a miscible solvent. Amoco indicated that this adjustment was made on a subjective basis after studying the saturation distributions in the model results. The negative adjustment averaged six per cent resulting in an average vertical miscible sweep efficiency from the models of 47.8 per cent. This value was applied to Layer 1 of the reservoir model. Amoco evaluated the vertical sweep efficiency of Layer 2 by using one of the Layer 1 cross sectional models with zero vertical permeability. This run predicted a sweep efficiency of 65.7 per cent and no immiscible gas displacement adjustment factor was applied.

Amoco submitted that the portion of the reservoir that was not miscibly sweep would be water flooded with the water flood recovery efficiency being equal to that calculated by the areal water flood model prediction. The ultimate recoverable reserves for each layer of the two layers used to describe the proposed solvent flood area of the pool were calculated by multiplying the areal sweep efficiency by the vertical sweep efficiency of the miscibly swept area and adding the appropriate water flood recovery to that area not miscibly swept. These calculations are outlined by Table 1 taken from the applicant's submission. Solvent flood recovery factors of 68.45 per cent and 62.63 per cent for Layers 1 and 2 respectively were calculated by this method. Application of these factors to the oil in place for each layer of the model yielded an ultimate recoverable reserve of 381,987 MSTB which is 65.8 per cent of the original oil in place.

Amoco stated that the recovery calculated by the two step solvent flood and water flood method would be comparable to that which would be obtained by evaluating the total recovery from the vertical model (both the miscible solvent displacement adjusted for immiscible dry gas displacement and the subsequent water displacement) and by applying an appropriate areal conformance factor which would be close to 100 per cent.

(2) Views of the Board

Since there was no direct evidence introduced by the applicant regarding the original oil in place for the pool other than to refer to the value used in the model study, the Board will continue to recognize the currently assigned original oil in place of 898,000 MSTB. The Board has reviewed the original oil in place estimate for the proposed solvent flood area of the pool and is in general agreement with the volume of 580,100 MSTB submitted by the applicant. The remainder of the oil in place in the pool is distributed on the basis of the pore volume for each recovery mechanism area. This distribution, compared to that submitted by the applicant, is outlined on Table 2.

The Board studied the water flood recovery factors assigned to the pool by reviewing the performance of the water flood and conducting a water flood simulation study on a representative cross sectional model of the pool. The only water flood performance available to date is from the western portion of the pool. A review of this performance and the simulation studies would indicate that a water flood recovery factor of 45 per cent is appropriate. The Board does not consider it necessary to review the primary depletion recovery factor or the water flood recovery factor of 30 per cent established for that eastern portion of the pool recently included in the water flood area. The ultimate water flood and primary depletion recoverable reserves are also outlined on Table 2.

The Board is of the opinion that the solvent flood sweep efficiencies predicted by Amoco's areal models may be somewhat optimistic and that the drilling of infill producing wells will be required for the predicted sweep efficiencies to be realized. Amoco has indicated that the required infill wells will be drilled within two years of project start up. The Board also notes that these sweep efficiencies will be realized only if mobility control is maintained in the reservoir.

The solvent flood recovery factor calculated by the Board's model studies is comparable to that determined by the applicant. The Board, however, has noted several major differences in the two models. As discussed previously, the Board included most of the pore volume in that portion of the model defined by the applicant as Layer 1 and provided for the injection of alternate slugs of solvent and water into each grid block at the injection face, on the basis of capacity. The Board concluded that a very small volume of solvent would be injected into the intervals equivalent to the applicant's Layer 2 and, as a result, this layer would not undergo significant miscible sweep. Amoco assumed injection of equal volumes of fluid to each layer and calculated a miscible recovery factor of some 52 per cent for Layer 2. The Board cannot agree with Amoco's treatment and finds that the recovery factors indicated by its model are equivalent to that proposed by Amoco because of the Board's interpretation of the distribution of oil in place and the injected solvent.

The Board believes that Amoco's evaluation of vertical sweep of Layer 2 (ie., assuming Layer 2 can be represented by a vertical cross sectional model of layer 1 with the vertical permeability values set at zero) is not valid. This method of evaluating the recovery efficiency does not provide for either a geological description of the part of the reservoir defined as Layer 2 or the distribution of injected fluid between the layers which have substantially different capacities.

The Board recognizes that the applicant's method of combining the results of the areal and vertical models enables the recoveries to be analysed on an individual layer basis. It is of the opinion that it would have been more appropriate to model the water flood recovery subsequently to the loss of miscibility by continuing the model runs once the saturation distributions at the time miscibility no longer existed rather than assigning an average water flood recovery factor to that portion of the reservoir immiscibly swept.

The Board has investigated the solvent flood sweep efficiency of a representative cross sectional model of the entire reservoir and has concluded that the recovery calculated by the applicant should be attainable, having regard for the distribution of oil in place determined by the Board and on the presumption that mobility control will be maintained and miscibility will be realized during the displacement of approximately 50 per cent of the reservoir pore volume. It is the Board's opinion that a recovery factor of 65 per cent should be set for the solvent flood scheme. This recovery factor is contingent upon the drilling of the appropriate infill wells. In the event that the operator has not undertaken to drill the infill wells within three years of the commencement of the scheme the Board will make an appropriate adjustment to the solvent flood recoverable reserves.

The Board has established that the recovery factor modifier to be assigned for the solvent flood recovery mechanism in this pool will be 3.50. This factor was calculated by dividing the recovery factor which would be set if the whole pool was flooded by solvent by the primary recovery factor. In evaluating the pool solvent flood recovery factor, it was assumed that the portion of the pool west of the proposed solvent flood scheme would realize a recovery of 65 per cent whereas the area east of the solvent flood scheme would realize a recovery equivalent to that set for the water flood recovery mechanism.

SOLVENT AND GAS SUPPLY

(1) Views of Amoco

Under examination at the hearing by Imperial and the Board, Amoco estimated that its partners and itself had reserved about two-thirds each of the condensate and gas required for the solvent flood scheme. Amoco would attempt to purchase the remaining required supply at market price, probably from Imperial.

Imperial also questioned Amoco with regard to the disposition of solvent and gas in the event of injection plant upset. Amoco expressed the view that most of the solvent and gas could be handled down the sales line as was the practice at the time of the hearing. Amoco stated that the handling of injection plant upset would have to be worked out between the Judy Creek Plant owners and Swan Hills South unit owners.

(2) Views of the Board

The Board is concerned that Amoco, at least at the time of the hearing, reported a shortage in the supply required to complete its scheme of about one-third of each of condensate and gas. The current high demand for these products is expected to continue and may make purchasing of this deficiency in supply difficult.

Nevertheless, the Board expects that Amoco would not proceed with construction of the needed injection facilities without having secured the needed supply. The Board will require a report to it on the status of solvent and gas supply arrangements not later than the commencement of operation of the scheme.

On the basis of the testimony given at the hearing, the Board expects that there will be adequate provision for injection plant upset in the design of the solvent flood system and that the scheme would be operated in such a manner that essentially no flaring would occur. Therefore, the Board requires that no hydrocarbons associated with the proposed injection scheme be flared except in special circumstances as may be approved by the Board in writing. The Board considers that Board Order No. GC43, for the conservation of gas produced in the Swan Hills South Field, is not applicable to this project and therefore any emergency flaring at the proposed facilities should not be interpreted as being a part of the flaring limitation specified in that order.

MONITORING AND SPECIAL CONSIDERATIONS

(1) Views of Amoco

The applicant stated that control of the injected fluids, both areally and vertically, will be an extremely important factor in ensuring that the solvent flood performs successfully. It expects that adverse fluid distributions can be corrected by altering the injection and production intervals in the various patterns.

Amoco stated that the use of radioactive isotopes in the injected solvent, gas and water is being considered as a means of monitoring the areal flow of injected fluids. It also intends to monitor the vertical distribution of the injected fluids with a regular program of vertical profiling of the fluids injected and will correct poor profiles through recompletions or replacement injection wells.

Amoco in its application requested recognition of the increase in reserves attributable to the schemes at such times as the project becomes effective and also requested approval of replacement of withdrawals in the solvent flood scheme on an annual basis.

(2) Views of the Board

The Board concludes that the applicant has recognized the importance of adequate, well designed performance monitoring. The Board, after giving consideration to the technical complexities of the displacement process and the performance history of similar schemes, also considers performance monitoring to have special significance for this scheme. Accordingly, the Board has introduced monitoring of the scheme, more stringent than usual, and this has been specified in Board Approval No. 1824. The most notable addition to the monitoring proposed by the applicant calls for the drilling of four infill observation wells for the purpose of monitoring scheme advance.

The Board agrees to Amoco's request for approval to replace withdrawals from the solvent flood area on an annual basis.

DECISION

1. The Board approves, under section 38 of The Oil and Gas Conservation Act, the scheme for recovery enhancement by solvent flooding a part of the Swan Hills South Beaverhill Lake A Pool. The terms and conditions of the approval are specified in Approval No. 1824.

2. Effective subsequently to the commencement of solvent injection and in accordance with section 10.150 of the Oil and Gas Conservation Regulations, the ultimate recoverable reserves for the solvent flood are established as 377 million stock tank barrels. The Board will assign separate projects areas, ultimate recoverable reserves and where applicable, recovery factor modifiers for the depletion mechanisms as outlined in Table 2.

3. The Board grants the application to replace reservoir withdrawals in the solvent flood area over a twelve month period subject to the conditions specified in Approval No. 1824.

4. The Board requires Amoco to report to it before the commencement of solvent injection on the volumes of solvent and gas under contract to Amoco for the proposed scheme.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

Dated at Calgary, Alberta
December 14, 1972

TABLE 1 TO DECISION 72-11

Calculated Recoveries - Areal & Vertical Models

Area 1

Layer 1 OOIP = 320,290

		10% Sor	5% Sor
Rec. Areal Model	=	86.2 MF	92.2
	=	46.7 WF	
Sweep Vertical Model	=	47.8 MF @ WOR = 10	
	=	100.0 WF	
M.F. Recovery	=	92.2 x .478 = 47.07	
W.F. Recovery	=	46.7 x (1 - .478) = 24.38	
		Total L-1 = 68.45	

Layer 2 OOIP = 259,859

		10% Sor	5% Sor
Rec. Areal Model	=	73.5 MF	78.8
	=	41.3 WF	
Sweep Vertical Model	=	65.7 MF	
	=	92.0 WF	
M.F. Recovery	=	78.8 x .657 = 51.77	
W.F. Recovery	=	41.3 x (.92 - .657) = 10.86	
		TOTAL L-2 = 62.63	

Oil Rec. = .6845 x 320,290 = 219,238

.6263 x 259,859 = 162,749

381,987

Total Recovery = 65.8%

(Reproduced from the Applicant's Submission)

ENERGY RESOURCES CONSERVATION BOARD

TABLE 2 TO DECISION 72-11

ORIGINAL OIL IN PLACE (OOIP)
AND ULTIMATE RECOVERABLE RESERVES

(Thousands of Stock Tank Barrels)

Depletion Mechanism	OOIP	Recovery Factor (%)	Ultimate Recoverable Reserves
Solvent Flood			
- Board	580,000	65	377,000
- Amoco	580,100	65.8	381,600*
Water Flood			
- Board	310,000	43.6	135,000
- Amoco	295,900	43.8	129,100*
Primary			
- Board	8,500	14	1,190
Total			
- Board	898,000		513,000
- Amoco	889,000		523,700**

* Recoverable reserves based on oil in place as of December 31, 1971.

** Amoco evaluated the ultimate recovery of the present oil in place and added the production to December 31, 1971, to obtain a pool total ultimate recoverable reserve of 523,700.

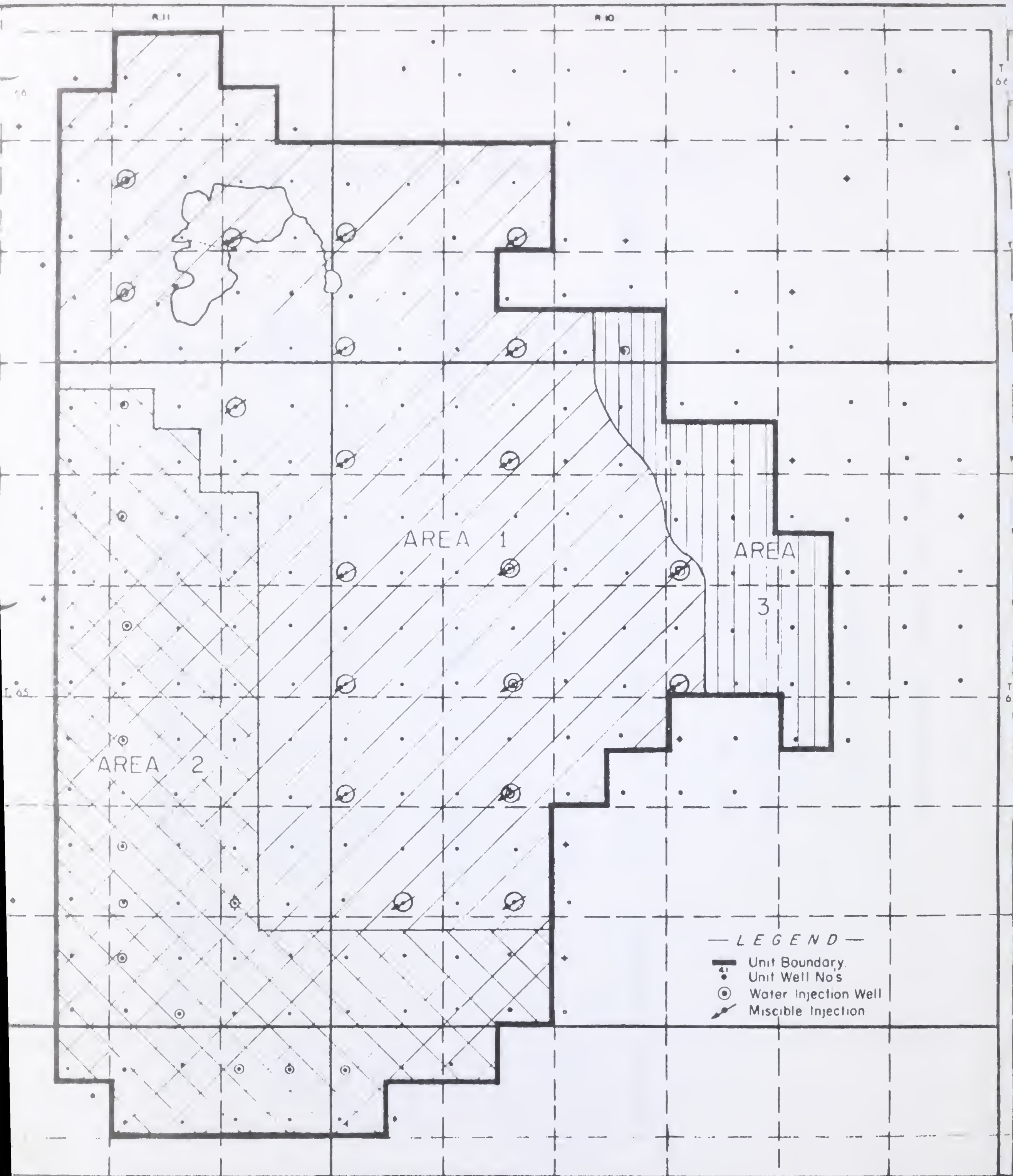


FIGURE NO. 1
TO DECISION 72-11
SOUTH SWAN HILLS UNIT
DEPLETION AREAS
REPRODUCED FROM THE APPLICANT'S SUBMISSION

APPENDIX A TO DECISION 72-11

ENERGY RESOURCES CONSERVATION BOARD

November 6, 1972

TO: All Operators

Swan Hills South Beaverhill Lake A Pool
Application No. 6416 - Solvent Flood

Amoco Canada Petroleum Company Ltd. has applied for an amendment of Approval No. 1262 to provide for solvent flooding of a portion of the subject pool. The scheme was considered at a public hearing on August 2, 1972.

The Board has completed its post hearing evaluation of issues most critical to the application and wishes to inform the applicant and interested parties of its decision as quickly as possible, so that the applicant may schedule its evaluation of the Board's decision and proceed with its scheme. The Board's detailed Decision will follow in a few weeks.

The Board has decided to grant the application and will assign a solvent flood recovery factor of 65 per cent to an oil in place of 580 million stock tank barrels in the solvent flood portion of the pool (referred to as Area 1 in the application). The solvent flood recovery factor will be recognized subsequent to commencement of solvent injection and in accordance with section 10.150 of the Oil and Gas Conservation Regulations. The Board will assign a separate project area and oil allowable to the solvent flood area at the time of solvent flood recognition.

The Board has attempted to study independently and in some detail the effects of reservoir heterogeneity and simultaneous injection of solvent and water slugs into both layer 1 and layer 2, as defined by the applicant. The Board is satisfied that the solvent bank is adequately sized and that the heterogeneities will not disrupt the competence of the solvent bank, provided that the favourable mobility ratio used by both Amoco and the Board in model studies will actually be obtained on the scale of the field. There appears to be

no satisfactory basis to quantitatively assess and verify attainment of the needed mobility control. Further the Board knows of no mature, successful field application of the proposed displacement process. Because of this the Board considers it necessary, while granting the application, to do so subject to requirements for scheme monitoring that are more stringent than normal. These monitoring requirements and other conditions are set out in Approval No. 1824, attached.

The Board notes that the applicant did not at the time of the hearing have under contract the gas supply necessary for completion of the scheme. The Board expects that the applicant would not proceed with the field installations without securing the necessary gas but asks the applicant to inform it of gas supply arrangements before commencing solvent injection.

ENERGY RESOURCES CONSERVATION BOARD

D R Craig

D. R. Craig, P. Eng.
Vice Chairman

Attachment

APPENDIX B TO DECISION 72-11

THE PROVINCE OF ALBERTA

THE OIL AND GAS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Amoco Canada Petroleum Company Ltd. for enhanced recovery of oil by the injection of water and of water, solvent and gas in parts of the Swan Hills South Beaverhill Lake A Pool and the Swan Hills South Beaverhill Lake B Pool

APPROVAL NO. 1824

WHEREAS the Oil and Gas Conservation Board by Approval No. 582 dated March 5, 1963, approved a scheme of Pan American Petroleum Corporation, now named Amoco Canada Petroleum Company Ltd., as such scheme was described in the letter of application dated December 21, 1962, from Pan American Petroleum Corporation to the Oil and Gas Conservation Board, and in testimony given at the hearing of the application on January 25, 1963, for pressure maintenance in parts of the Swan Hills South Beaverhill Lake A Pool and the Swan Hills South Beaverhill Lake B Pool; and

WHEREAS the Oil and Gas Conservation Board by Approval No. 1262 superseding Approval No. 582, granted the application dated January 1, 1970, and addenda thereto, for amendment of the said approval; and

WHEREAS Amoco Canada Petroleum Company Ltd. has applied for amendment of the said approval; and

WHEREAS the Board considers it desirable to revise and consolidate the approval.

THEREFORE, the Energy Resources Conservation Board, pursuant to The Oil and Gas Conservation Act, being chapter 267 of the Revised Statutes of Alberta, 1970, hereby orders as follows:

1. The scheme of Amoco Canada Petroleum Company Ltd. (hereinafter called "the Operator") for

   (a) enhanced recovery of oil by water injection into the parts of the Swan Hills South Beaverhill Lake A Pool and the Swan Hills South Beaverhill Lake B Pool shown marked Part 1 on Appendix A hereto, as described in applications and testimony hereinbefore referred to, and

(b) enhanced recovery of oil by water, solvent and gas injection in the part of the Swan Hills South Beaverhill Lake A Pool shown marked Part 2 on Appendix A, as described in the application dated June 6, 1972, and in testimony given at the hearing of the application on August 2, 1972,

is approved, subject to the terms and conditions herein contained.

PART 1
WATER FLOOD AREA

2. (1) Water may be injected to the Swan Hills South Beaverhill Lake A Pool and to the Swan Hills South Beaverhill Lake B Pool without restrictions as to the apportionment between the pools of the quantities injected, in the wells located in

(a) Legal Subdivision 12 of Section 31, Township 64, Range 10, West of the 5th Meridian; Legal Subdivisions 10 and 12 of Sections 36, both in Township 64, Range 11, West of the 5th Meridian; Legal Subdivisions 2 and 12 of Section 2, Legal Subdivisions 4 and 12 of Section 11 and Legal Subdivisions 12 of Sections 14, 23, 26 and 35, all in Township 65, Range 11, West of the 5th Meridian; and

(b) Legal Subdivisions 2 of Sections 23 and 26, Legal Subdivision 4 of Section 34, and Legal Subdivision 2 of Section 35, all in Township 65, Range 10, West of the 5th Meridian and Legal Subdivisions 2 of Sections 3 and 4, both in Township 66, Range 10, West of the 5th Meridian.

(2) Natural gas liquids may be injected into the Swan Hills South Beaverhill Lake A Pool in the well located in Legal Subdivision 4 of Section 12, Township 65, Range 11, West of the 5th Meridian.

3. (1) The injection of water, substantially in accordance with the scheme, having commenced in the wells referred to in clause 2, subclause (1), subclause (a) shall continue.

(2) The injection of water, substantially in accordance with the scheme, shall commence in the wells referred to in clause 2, subclause (1), subclause (b) on or about September 1, 1972, and shall continue after the commencement.

(3) The injection of natural gas liquids, substantially in accordance with the scheme, having commenced in the well referred to in clause 2, subclause (2) shall be terminated on or before January 1, 1974.

4. The water injected to the wells referred to in clause 2, subclause (1) shall be, within three months of the date of commencement of injection and thereafter, in sufficient volumes to maintain, in the opinion of the Board, a suitable balance between water injected to and fluids withdrawn from that part of the pool.

5. No production shall be taken from any spacing unit wherein the reservoir pressure is below 1800 pounds per square inch gauge unless the Board, upon application, otherwise permits.

PART 2
SOLVENT FLOOD AREA

6. Water, solvent and gas may be injected to the Swan Hills South Beaverhill Lake A Pool in the wells located in

(a) Legal Subdivision 4 of Section 7, Legal Subdivision 2 of Section 8, Legal Subdivisions 4 of Sections 18, 19, 22, 27, 30 and 31, and Legal Subdivision 2 of Section 32, all in Township 65, Range 10, West of the 5th Meridian; Legal Subdivision 2 of Section 5, Legal Subdivisions 4 of Sections 6 and 7, and Legal Subdivision 2 of Section 8, all in Township 66, Range 10, West of the 5th Meridian; Legal Subdivision 12 of Section 36, Township 65, Range 11, West of the 5th Meridian; and Legal Subdivision 4 of Section 12, Township 66, Range 11, West of the 5th Meridian; and

(b) Legal Subdivisions 2 of Sections 17, 20 and 29, all in Township 65, Range 10, West of the 5th Meridian; and Legal Subdivisions 12 of Sections 2 and 11, both in Township 66, Range 11, West of the 5th Meridian.

7. (1) The injection of water substantially in accordance with the scheme in the wells referred to in clause 6, subclause (a) shall not exceed 1,000,000 barrels in any well prior to the commencement of injection of solvent to that well.

(2) The Operator shall, in accordance with the scheme, cease injection of water to the wells referred to in clause 6, subclause (b) and shall not resume water injection until after the commencement of solvent injection.

8. Alternate volumes of solvent and water and gas and water shall be injected, in accordance with the scheme, in the wells described in clause 6, and at the end of each injection cycle the ratio of the volume of solvent or gas injected to the volume of water injected during that cycle shall be 1.25, where the volume of each fluid is expressed in reservoir barrels.

9. (a) The Operator shall submit to the Board by December 31, 1972, the schedule for injection of alternate volumes of solvent and water and gas and water.

(b) Injection having commenced in accordance with subclause (a) shall continue.

10. The cumulative volume of solvent to be injected to that part of the Swan Hills South Beaverhill Lake A Pool shall be not less than 82 million barrels at reservoir conditions and shall be so distributed that each of the wells referred to in clause 6 receives a volume of solvent not less than 10 per cent of the hydrocarbon pore volume of the injection pattern associated with the well.

11. The cumulative volume of gas to be injected to that part of the Swan Hills South Beaverhill Lake A Pool shall be not less than 246 million barrels at reservoir conditions and shall be so distributed that each of the wells referred to in clause 6 receives a volume of gas not less than 30 per cent of the hydrocarbon pore volume of the injection pattern associated with the well.

12. (1) Subject to subclause (2), the fluids injected to that part of the Swan Hills South Beaverhill Lake A Pool shall be, within three months of the date of commencement of solvent injection and for each annual period thereafter, in sufficient volumes to maintain, in the opinion of the Board, a suitable balance between fluids injected to and fluids withdrawn from that part of the pool.

(2) Commencing with the first month of each annual period specified in subclause (1), the cumulative replacement ratio at the end of the first month and each month thereafter in each annual period shall be equal to or greater than unity.

13. The Operator shall control the injection and withdrawals in a manner such that the reservoir pressure at the solvent displacement front is maintained at or above 2350 pounds per square inch gauge.

14. For the purpose of this approval "solvent" means a suitable mixture of hydrocarbons ranging from methane to pentanes plus, but consisting largely of methane, ethane and propane, with the ethane plus content of the solvent being not less than 53 mole per cent.

15. The Operator shall upon commencement of solvent injection, follow a program of sampling and analysis in accordance with the following rules:

1. The compositions of the solvent and gas injected to the pool shall be determined and submitted to the Board no less than once each month until such time as the Board permits, in writing, a less frequent interval.

2. The Operator shall select 20 producing wells distributed throughout the solvent flood area and shall obtain at least one gas sample every three months and analyse it to determine methane, propane and butanes content and using the results therefrom and applying equilibrium calculations, determine the methane, propane and butanes content of the crude oil associated with the sampled gas.

3. Before a sample is obtained in accordance with rules 2 and 5 hereof, the Operator shall produce the well until the volume of gas, oil and water production at reservoir conditions is at least three times the volumes of open casing, tubing and flow line to the point of sampling.

4. The Operator shall determine the flowing gas-oil ratio in the wells referred to in rule 2 and calculate at that gas-oil ratio the reference level amount, in pounds per stock tank barrel of oil, of methane, propane and butanes content of the combined oil and gas stream which would be produced, in the absence of solvent and gas injection.

5. When breakthrough of injected solvent or gas is indicated in any of the wells referred to in rule 2, or in any other producing well in the project area, the Operator shall obtain at least one gas sample each month from that well and analyse it in accordance with rules 3 and 4.

16. (1) The Operator shall monitor the vertical distribution of injected fluids by an injection profile survey to be run at least every year from the commencement of injection, in each of the wells referred to in clause 6, with the first program starting with the injection of solvent.

(2) If an injection well is reworked, an injection profile shall immediately be taken.

17. The Operator shall drill at least four infill observation wells, the first well to be completed by January 1, 1974, in locations to be approved by the Board, and shall obtain fluid samples for evaluation of solvent content in accordance with clause 15.

18. The Operator shall monitor the position of the injected fluids, with a program to be approved by the Board, by logging the water, solvent and gas with suitable tracers.

19. In addition to the normal reporting requirements specified in section 12.130 of the Oil and Gas Conservation Regulations, the Operator shall report in each progress report submitted for the scheme

(a) in graphical form,

(i) for each well, the producing gas oil ratio, water-oil ratio and oil rate in barrels per day,

(ii) the reference level amounts in pounds per stock tank barrel of oil, of methane and the sum of propane and butanes determined in accordance with clause 15, rules 2, 3 and 4, and

(iii) the amount in pounds per stock tank barrel of oil, of methane and the sum of propane and butanes determined in accordance with clause 15, rules 2, 3, 4 and 5.

(b) instances of solvent breakthrough and the implications of the breakthrough on efficacy of the scheme, and

(c) the significance of the information obtained in accordance with clauses 15, 16, 17 and 18.

20. The Operator shall, in addition to normal reporting requirements, report to the Board three years after commencement of solvent injection concerning

(1) the overall efficacy of the scheme including an assessment of gravity override, cross flow and fingering that may be occurring, and

(2) the status of the infill drilling program.

21. Board Approval No. 1262 is superseded.

22. The Board,

(a) upon its own motion, or

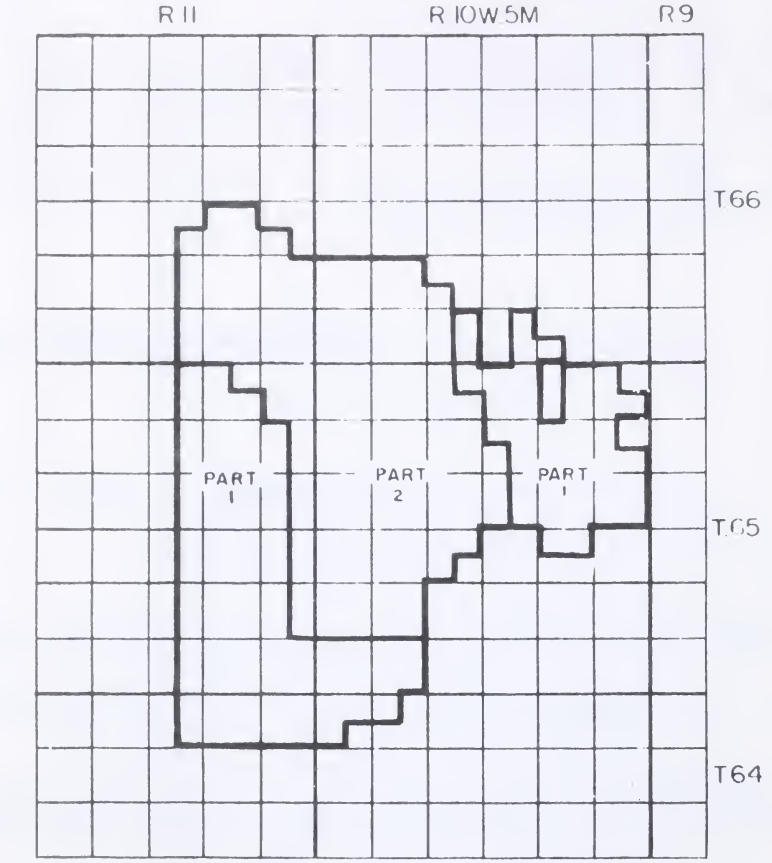
(b) upon the application of an interested person,

may vary the terms and conditions hereof or rescind this approval.

MADE at the City of Calgary, in the Province of Alberta, this 6th day of November, A. D. 1972.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman



APPENDIX A TO APPROVAL NO. 1824

IN THE SWAN HILLS SOUTH FIELD

ENERGY RESOURCES CONSERVATION BOARD

Decision 72 - 12
Proceeding No. 6592

GAS WELL PRODUCTION ALLOWABLES

HEARING

A hearing was held by the Board for the purpose of hearing representations respecting the need for and the data to be used in establishing maximum daily production rates (Qmax) for gas wells in the pools listed in Attachment 1.

The hearing was held by the Board in Calgary, Alberta, on October 25, 1972, with D.R. Craig, P.Eng. and V.E. Bohme, P.Eng. sitting.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Aquitaine Company of Canada Ltd.	D.J. Cartwright, P.Eng. E.R. Abernethy	Aquitaine
Canadian Montana Gas Co. Ltd.	W.D. Butterwick	Canadian Montana
Canadian Superior Oil Ltd.	M.T. Alexandre, P.Eng. D.L. Jackson, P.Eng.	Canadian Superior
Chevron Standard Limited	R.A. Filgate, P.Eng.	Chevron
Dome Petroleum Limited	R.H. Johnson, P.Eng.	Dome
Gulf Oil Canada Limited	W.K. Good, P.Eng. G.C.J. Hos, P.Eng. S.B. Beveridge, P.Eng. (Intercomp Resource Development and Engineering Ltd.)	Gulf
Home Oil Limited	F.R. Erick Mulder, P.Eng.	Home
Hudson's Bay Oil and Gas Company Limited	S.K. Chakravorty, P.Eng. M.B. Field H.W.G. Kershaw, P.Eng.	Hudson's Bay
Shell Canada Limited	J.E. Davidson, P.Eng. G.L. Burkholder	Shell

	Represented by	Abbreviation Used in Report
Westcoast Petroleum Ltd.	M. Fazil, P.Eng. W.L. Williamson, P.Eng.	Westcoast
Board Staff	D.G. Pearson, P.Eng. G.M. Malin, P.Eng. J.A. Stayura	

SUBMISSIONS AND FINDINGS OF THE BOARD

Eight pools were considered for either Qmax (daily maximum allowable) restrictions or Good Production Practice status. No pools were considered with respect to daily average allowable (MPR_G). Each pool is considered below.

Burnt Timber Rundle A Pool

Views of Shell

Shell submitted that the possible explanations for the production of formation water from the well in Legal Subdivision 6 of Section 22, Township 31, Range 9, West of the 5th Meridian, are: water coning, lateral encroachment from the aquifer and interstitial water. It stated, however, that the first two possibilities were largely discounted having regard for the presence of a layer of dense anhydritic dolomite separating the main productive member in the Burnt Timber structure from any water in the Pekisko formation and the location of the water level which is about 2000 feet down dip from the lowermost productive well. Shell further stated that log interpretations indicated the presence of several streaks of high interstitial water saturation throughout the completion interval of the subject well which could explain the level of water production being above that of water of condensation. It also submitted that insufficient data are presently available to assess future reservoir behaviour. Notwithstanding the water production problems, Shell asked that the current drawdown factor of 0.80 be continued for the wells in Legal Subdivision 6 of Section 1 and Legal Subdivision 6 of Section 22, and a drawdown factor of 0.85 be continued for the well in Legal Subdivision 10 of Section 12 until further data become available. It also indicated that the well in Legal Subdivision 6 of Section 22 would be monitored each productive quarter to evaluate possible changes in water production characteristics.

Views of the Board

The Board is in general agreement with Shell's explanation for the present level of water production being above that of water of condensation. The Board, however, believes that the level of water production should decline as the streaks of high water saturation are depleted. The Board therefore agrees with Shell's proposal to monitor the

well in Legal Subdivision 6 of Section 22 each productive quarter to evaluate possible changes in water production characteristics. The Board believes that water coning should not be discounted as possibly contributing to a water production problem at some time in the future. The Board considers that, until the production performance of the wells in the pools can be further evaluated, the current drawdown factors of 0.80 for the wells in Legal Subdivision 6 of Section 1 and Legal Subdivision 6 of Section 22 and 0.85 for the well in Legal Subdivision 10 of Section 12, are appropriate.

Harmattan-Elkton D-3 A Pool

Views of Canadian Superior

Canadian Superior requested that the current suggested Qmax rates for wells in this pool, with the exception of the rate for the well located in Legal Subdivision 1 of Section 17, Township 32, Range 4, West of the 5th Meridian, be retained until Canadian Superior's reservoir simulation study of the Harmattan-Elkton D-3 A Pool is completed and submitted to the Board. Canadian Superior recommended a decrease in the Qmax rate for the well located in Legal Subdivision 1 of Section 17 from 6600 thousand cubic feet per day (Mcfd) to 4000 Mcfd in the light of a significant increase in water-gas ratio at this well based on the comparison between the results of the current production test and the previous tests. Canadian Superior stated that its three-dimensional mathematical simulation study will determine the effect of the underlying aquifer and the effect of producing rate on ultimate recovery and that the results of the study will be submitted as a supplement to its current submission sometime near the end of 1972.

Views of the Board

The Board agrees with Canadian Superior's proposal to retain the Qmax rates at the current levels for all wells in this pool except for the well located in Legal Subdivision 1 of Section 17. The Board also agrees with Canadian Superior that the Qmax for this well should be decreased to 4000 Mcfd. These rates are established for an interim period pending the receipt of the results of Canadian Superior's reservoir simulation study which the Board understands will be completed by the end of 1972.

Kaybob South Beaverhill Lake A Pool

Views of Chevron

Chevron requested that maximum daily gas production rates for the wells in Unit 3 be continued as specified in Board Decision 71-19. Recent production tests on its wells indicate that no bottom water is being produced.

Views of Hudson's Bay

Hudson's Bay requested that no gas well production allowables be imposed on wells in Unit 1 and Unit 2. It submitted that the present method of operation, in which maximum producing rates are established on the basis of actual production experience and numerical models calibrated by Thermal Decay Time (TDT) logging data, permits proper rate control without arbitrary and inconsistent choices of drawdown factors. Hudson's Bay further submitted that these rates were not necessarily critical rates but were established to reflect such operational problems as hydrate formation and limited tubing capacity.

Views of the Board

The Board observes that no wells in Unit 3 are experiencing water problems and is prepared to accept the current drawdown factors as specified in Board Decision 71-19 for the wells in this unit.

The Board is concerned with the excessive water-gas ratios experienced at several wells in Unit 1 and Unit 2 but is satisfied that the operator is continuing its efforts to control water production. The Board notes that Hudson's Bay has imposed drawdown factors equal to or greater than 0.90 on all wells except in one case where a minimum daily gas rate of 3000 Mcfd was necessary. The Board therefore is prepared to accept the Qmax rates recommended by Hudson's Bay.

Lone Pine Creek D-3 A Pool

Views of Dome

Dome submitted that the water production from the well in Legal Subdivision 10 of Section 32, Township 30, Range 27, West of the 4th Meridian was not in excess of the water of condensation and accordingly requested that no change be made to the maximum daily allowable for this well.

Views of Hudson's Bay

Hudson's Bay submitted that the drawdown factor should be assigned on an individual well basis since water coning and channelling are dependent on localized formation characteristics that vary from well to well. It requested that a drawdown factor of 0.85 be continued for the wells in Legal Subdivision 10 of Section 4 and Legal Subdivision 7 of Section 5 and that the current maximum daily rate of 1400 Mcfd be retained for the well in Legal Subdivision 6 of Section 33.

Views of the Board

The Board agrees with Dome and Hudson's Bay that a drawdown factor of 0.85 is appropriate for the wells in the pool. The Board, however, is concerned with the number of instances in which assigned Qmax rates were exceeded in the well in Legal Subdivision 10 of Section 32. Having regard for the apparent high level of water production now evident in the well in Legal Subdivision 6 of Section 33 and considering that the assigned Qmax rate in this particular well was exceeded on several occasions during 1971, the Board believes that more stringent control over production rates for wells in this pool may prevent this higher level of water production from occurring in wells now producing only water of condensation. The Board, therefore, will set maximum daily production rates for wells in this pool by Board order.

Lookout Butte Rundle A Pool

Views of Gulf

Gulf submitted that of the ten producing wells in the pool only BA Lookout Butte 11-31-1-28, BA Lookout Butte 4-32-1-28, BA Lookout Butte 13-6-2-28 and BA Lookout Butte 4-13-2-29 are producing formation water. It submitted that the results of the coning behaviour model studies conducted on the pool and production performance of wells currently producing water indicated that a reduction in the gas production rate resulted in an increase in the water influx rate for a given cumulative production. Its studies further indicated that the mechanism of water production in the pool is the result of coning and water influx and that water influx is the predominate factor associated with the rapid rise in water-gas ratio. Gulf therefore concluded that the increased water-gas ratios with lower production rates at a given cumulative production indicate that ultimate recovery from individual wells and from the pool will not be increased by substantial restriction of the production rates. It therefore requested that no maximum daily rates be assigned for wells in the pool but, should some control be deemed necessary, that no Qmax rate be set below 3000 Mcfd.

Views of the Board

The Board agrees in part with Gulf's contention that the increased water-gas ratios with lower production rates at a given cumulative production indicate that ultimate recovery from the pool will not be increased by substantial restriction of the production rates. The Board believes, however, that the pressure gradients which exist around each well bore remain a function of production rate, and therefore that production rates should be controlled in certain wells to prevent premature migration of water in the reservoir. It accepts Gulf's request that a minimum Qmax rate of 3000 Mcfd is necessary to alleviate the hydrate problems which occur

at lower producing rates, and accordingly will assign a Qmax rate of 3000 Mcfd in those instances where the calculated Qmax is below this value.

The Board believes that the performance of this pool should again be considered at the 1973 Qmax hearing to compare the results of the coning simulation study with the production performance to that time.

Pendant D'Oreille Mannville A Pool

Views of Home

Home submitted that the amount by which the production from the well located in Legal Subdivision 6 of Section 16, Township 3, Range 8, West of the 4th Meridian exceeded the Qmax was of such small magnitude as to be negligible. It also submitted that the occasions of exceeding the Qmax at the well located in Legal Subdivision 7 of Section 17, Township 3, Range 8, West of the 4th Meridian were the result of field operational difficulties associated with the adverse weather conditions and unstable producing characteristics of this well. Home stated that it proposes to place a smaller bottom hole choke in the well located in Legal Subdivision 7 of Section 17 and to install a new compressor in the area which may improve the operating efficiency. Home said that the water-gas ratios have remained constant for its wells except for the well located in Legal Subdivision 10 of Section 5, Township 3, Range 8, West of the 4th Meridian at which well the water-gas ratio increased from two barrels per million to four barrels per million. In reply to a question regarding whether the Qmax should be applied on a daily basis, Home said that the Qmax is for the purpose of preventing harm to the producing characteristics of a well and that it could see no reason why daily operations should be affected by the Qmax. Its main concern was that the Qmax should not be exceeded on a monthly basis. Home submitted that more operating flexibility was needed and recommended that the Board reduce the drawdown factor to 0.80 for its wells in the pool and set Qmax rates not less than 950 Mcfd and 1000 Mcfd for the wells located in Legal Subdivision 6 of Section 16 and Legal Subdivision 7 of Section 17 in Township 3, Range 8, West of the 4th Meridian respectively and in the range of 700 - 750 Mcfd for the well located in Legal Subdivision 7 of Section 18, Township 3, Range 8, West of the 4th Meridian.

Views of Hudson's Bay

Hudson's Bay submitted that the apparent increase in the reported water-gas ratio at the well located in Legal Subdivision 10 of Section 8, Township 3, Range 8, West of the 4th Meridian was due to an accounting error in the reporting of an in-line flow test taken in February, 1972. Hudson's Bay requested that in view of the position of this well with respect to flank water and the negligible increase in water-gas ratio the drawdown factor of 0.80 be retained for this well.

Views of the Board

The Board agrees with Home and Hudson's Bay that a drawdown factor of 0.80 should be retained for the wells located in Legal Subdivisions 10 of Sections 7 and 8, Township 3, Range 8, West of the 4th Meridian. Both wells have over 20 feet of gas pay between the lowest perforations and the gas water interface and produce only water of condensation. The well in Legal Subdivision 10 of Section 5, Township 3, Range 8, West of the 4th Meridian has experienced an increase in water production from two barrels per million cubic feet to four barrels per million cubic feet during the past year, the well in Legal Subdivision 6 of Section 16 produces at a water-gas ratio greater than the water of condensation, and both wells have less than twenty feet of pay between the lowest perforations and the gas-water interface. The Board believes that a drawdown factor of 0.85 is appropriate for each well.

For the wells in Legal Subdivisions 7 of Sections 17 and 18, the Board will establish a Qmax rate of 700 Mcfd for each well. The Board notes that the water-gas ratio has remained relatively constant in these wells and it has established a Qmax rate higher than that calculated in order to minimize operating problems associated with production from these wells.

The Board notes that the Qmax rates were exceeded in 1972 during the months from January to October at the well located in Legal Subdivision 6 of 16 and for the first ten months of 1972 except for the month of March at the well located in Legal Subdivision 7 of 17. While the Board appreciates that the Qmax rates may be occasionally exceeded due to operation difficulties associated with adverse weather conditions and well fluctuations, it is concerned that the operator has not taken the necessary steps to ensure that these rates are not continually exceeded. The Board notes that modifications to the well equipment and field facilities are to be made during the coming year which may improve the operations in this field. The Board, having regard for the performance of the wells and the operation in the past, will set the maximum daily production rate by Board order.

Stanmore Viking A and Stanmore Viking B Pools

Views of Westcoast

Westcoast submitted that of the nine producing wells in the pool only Westcoast Sulpetro Smore 11-30-29-10 and Sulpetro Westcoast Smore 7-9-30-11, which is dually completed in the Stanmore Viking A Pool and Stanmore Viking B Pool, are producing formation water. It stated that the water production from the well located in Legal Subdivision 11 of Section 30, which is perforated over aninterval considerably higher in the formation than the apparent gas-water contact, suggested that an anomolous situation was present which could not be clearly defined. Westcoast also stated that the water production from the well located in Legal Subdivision 7 of Section 9 was due to the commingling of the wet gas from the Stanmore Viking B Pool with the dry gas from the Stanmore Viking A Pool. It requested that the gas production from the Stanmore Viking A and Stanmore Viking B Pools continue to be controlled through Qmax for

individual wells based on the appropriate drawdown factors and the 1972 absolute open flow tests. Westcoast further requested that in order to prevent hydrate formation and liquid loading in the tubing no maximum daily production rate be set below 750 Mcfd.

Views of the Board

The Board is unable to adequately explain the level of water production from the well located in Legal Subdivision 11 of Section 30 but considers poor reservoir rock quality in the vicinity of this well to be a partial explanation for a higher gas-water interface at this well. The Board is reluctant to establish a drawdown factor of 0.70 for any well until evidence is clearly shown to indicate that no harmful water migration will occur. The Board therefore believes that the current drawdown factor of 0.80 be continued for wells in the Stanmore Viking A Pool with the exception of the well located in Legal Subdivision 11 of Section 30. Having regard for the high level of water production evident in this well, the Board believes a drawdown factor of 0.90 is appropriate. The Board further believes that a drawdown factor of 0.90 is appropriate for wells in the Stanmore Viking B Pool.

The Board notes that approval of comingling production from the Stanmore Viking A Pool and the Stanmore Viking B Pool at the well located in Legal Subdivision 7 of Section 9 has been granted and understands that the combined production from the two pools is measured at the surface. The Baord believes that the same drawdown factor should be applied to the production rate from each pool. The Board therefore considers that a drawdown factor of 0.90 is appropriate for this well.

Strachan D-3 A Pool

Views of Aquitaine

Aquitaine submitted that the water production in excess of the water of condensation at the well located in Legal Subdivision 7 of Section 32, Township 37, Range 9, West of the 5th Meridian is due to water channelling up along the well bore caused by a poor cement bond along the casing between the aquifer and the perforated interval of this well. Aquitaine also expressed the opinion that several strati of very low permeability between the aquifer and the perforated interval of the well located in Legal Subdivision 10 of Section 31, Township 37, Range 9, West of the 5th Meridian precluded the possibility of water coning ever being a problem at this well. Aquitaine stated that the apparent rise in the water-gas ratio at the well located in Legal Subdivision 10 of Section 31 was due to an error in the prorationing of the total monthly water production between the wells located in Legal Subdivision 7 of Section 32 and Legal Subdivision 10 of Section 31, and that the well is producing at a water-gas ratio of 0.73 barrels per million consistent with the water of condensation. Aquitaine submitted that pressure history of the pool indicates that excellent pressure communication exists in this pool, and that ultimate recovery from

this pool would not be affected by high production rates of if a well was lost due to water coning. Therefore, Aquitaine submitted that withdrawal rates from this pool should be left to the discretion of the operators in the pool and requested that good production practice status be established for this pool.

Views of Gulf

Gulf said that the thick pay section of this pool and the good permeability provide for excellent pressure communication between the different parts of the reservoir. The various pressure measurements confirm that there is good communication in the pool. Gulf further submitted that the material balance study of this pool indicated that the aquifer underlying the pool is of limited areal extent. Based on evidence of an insignificant water influx and the excellent reservoir communication in this pool, only a few wells would be required to drain the reserves. Gulf contended that because of the high costs of drilling additional wells in this pool, it was essential to produce all wells at as high a rate as possible without coning formation water. Gulf submitted that its coning study supports Aquitaine's belief that the free water production in the well located in Legal Subdivision 7 of Section 32, Township 37, Range 9, West of the 5th Meridian is a result of mechanical problems rather than water coning. Its study indicated that the plant inlet pressure restricts the production rate of its wells sufficiently to preclude coning of formation water at these wells. Gulf therefore suggested that the Omax limitations currently in effect in the pool be removed, but if some limitations were deemed necessary, drawdown factors no greater than those corresponding to the estimated 1973 deliverability be utilized in calculating Omax rates for individual wells.

Views of the Board

The Board has reviewed the performance of the wells in the Strachan D-3A Pool and the study prepared by Gulf regarding critical coning rates and is prepared to accept Aquitaine's and Gulf's conclusion that the free water production from the well located in Legal Subdivision 7 of Section 32 is due to mechanical problems rather than water coning from the aquifer. The Board, having regard for the above coning study and the well production rates proposed by Aquitaine and Gulf, agrees that restriction of the production from the wells through Omax limitations is not required to prevent coning or to optimize recovery. The Board is therefore prepared to permit production from this pool at rates consistent with good production practice. The Board expects that the operators will exercise appropriate control of the production rate from each well to ensure that maximum ultimate recovery be obtained from the pool and that the performance of the wells be continually observed for potential water producing problems.

DECISION

The Board adopts, effective January 1, 1973, the drawdown ("f") factors and the maximum daily gas production rates summarized in Attachment I.

ENERGY RESOURCES CONSERVATION BOARD

D.R. Craig
Vice Chairman

DATED at Calgary, Alberta
December 28, 1972

Attachment I to Decision No. 72-12

Summary of Operator Proposals and Board Decision

Pool	Operator Proposals	Board Decision
Burnt Timber Rundle A	No change in current drawdown factors.	No change in current drawdown factors. Well — 'f' Shell 3 Burnt Timber 6-1-31-9 — 0.80 Shell 2 Burnt Timber 6-22-31-9 — 0.80 Shell 5 Burnt Timber 10-12-31-9 — 0.85
Harmattan-Elkton D-3 A	No change in current Qmax rates except a decrease to 4000 Mcfd for the well in LS 1 of 17.	Adopt Qmax rates as recommended by Canadian Superior.
Kaybob South Beaverhill Lake A	Chevron - No change in current maximum production rates Hudson's Bay - Maximum production rates based on coning simulation studies	No change in current maximum production rates. Adopt maximum production rates as recommended by Hudson's Bay.
Lone Pine Creek D-3 A	Dome - No change in current Qmax rate for the well in LS 10 of 32. Hudsons' Bay - No change in drawdown factors for the wells in LS 10 of 4 and LS 7 of 5 or in current Qmax rate for well in LS 6 of 33.	Assign Qmax rates by Board Order using a drawdown factor of 0.85.

Pool	Operator Proposals	Board Decision
Lookout Butte Rundle A	Good Production Practice	Maintain current drawdown factors or minimum Qmax rate of 3000 Mcfd.
Pendant D'Oreille Mannville A	Hudson's Bay - No change in current drawdown factor for the well in LS 10 of 8. Home - Change drawdown factors to 0.80 for its wells. Minimum Qmax rates of 950 Mcfd for the well in LS 6 of 16, 1000Mcfd for the well in LS 7 of 17, and 700-750 Mcfd for the well in LS 7 of 18.	Assign Qmax rates by Board Order.

Well	'f'	Qmax (Mcfd)
HB Pendant D'Oreille 10-8-3-8	0.80	4600
Home CMG Pendor 10-7-3-8	0.80	900
Home CMG Pendor 10-5-3-8	0.85	860
Home CMG Pendor 6-16-3-8	0.85	620
Home CMG Pendor 7-17-3-8	-	700
Home CMG Pendor 7-18-3-8	-	700

Pool	Operator Proposals	Board Decision
Stanmore Viking A & B	Qmax rates be based on individual drawdown factors with minimum Qmax rates of 750 Mcfd.	No change in current drawdown factors except a drawdown factor of 0.90 will be used for the Qmax rate for the Viking A Pool, for the well Sulpetro Westcoast Smore 7-9-30-11. Minimum Qmax rate of 750 Mcfd.
Strachan D-3 A	Good Production Practice	Good Production Practice.

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